Mid-Con Energy Partners, LP
Form 424B1
October 17, 2012
Table of Contents

Filed pursuant to Rule 424(b)(1)
Registration No. 333-184120

PROSPECTUS

Mid-Con Energy Partners, LP

4,000,000 Common Units

Representing Limited Partner Interests

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.

We are offering 1,000,000 common units and Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P. are offering an aggregate of 3,000,000 common units in this offering.

Our common units are traded on the NASDAQ Global Market under the symbol MCEP. On October 12, 2012, the last reported sales price of our common units on the NASDAQ Global Market was $22.84 per common unit.

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

Investing in our common units involves risks. See Risk Factors beginning on page 24.

These risks include the following:

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

- 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.

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.

Our general partner, who controls us, has conflicts of interest with, and owes limited fiduciary duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

Neither we nor our general partner have any employees, and we rely solely on an affiliate of our general partner to manage and operate our business. The individuals who manage us also provide substantially similar services to affiliates of our general partner, and thus are not solely focused on our business.

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

Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors.

Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

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

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

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

PRICE $21.20 PER COMMON UNIT

	Per Common Unit	Total
Public offering price	$ 21.20	$ 84,800,000
Underwriting discount	$ 0.848	$ 3,392,000
Proceeds, before expenses, to Mid-Con Energy Partners, LP	$ 20.352	$ 20,352,000
Proceeds, before expenses, to Selling Unitholders	$ 20.352	$ 61,056,000

The Selling Unitholders have granted the underwriters a 30-day option to purchase up to an additional 600,000 common units on the same terms and conditions as set forth above if the underwriters sell more than 4,000,000 common units in this offering.

The underwriters expect to deliver the common units on or about October 22, 2012.

RBC Capital Markets **Raymond James** **UBS Investment Bank** **Wells Fargo Securities**

Baird **Oppenheimer & Co.** **Stephens Inc.**

October 16, 2012

As of December 31, 2011, we had total estimated proved reserves of 10.0 MMBoe, 99% of which were oil and 69% of which were proved developed, both on a Boe basis. As of December 31, 2011, Mid-Con Energy Operating, Inc. operated 99% of our reserves and 96% of such reserves were being operated under waterflood, both on a Boe basis.

As of June 30, 2012, we had 320 gross producing wells (224 net wells), 149 gross injection wells (97 net wells), and 81 gross wells (67 net wells) shut-in or waiting on completion.

Table of Contents

TABLE OF CONTENTS

Table of Contents

Table of Contents

You should rely only on the information contained in this prospectus. We have not, and the underwriters and Selling Unitholders have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters and Selling Unitholders are not, making an offer to sell these securities in any jurisdiction where such an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus only. Our business, financial condition, results of operations and prospects may have changed since that date.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. Please read Risk Factors and Forward-Looking Statements.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data is also based on our good faith estimates. Although we believe these third-party sources are reliable and that the information is accurate and complete, we have not independently verified the information.

Table of Contents

PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including Risk Factors and the historical and unaudited financial statements and the notes to those financial statements. The information presented in this prospectus assumes that the underwriters do not exercise their option to purchase up to an additional 600,000 common units from the Selling Unitholders, unless otherwise indicated. As used in this prospectus, unless we indicate otherwise:

- *Founders collectively refers to Charles R. Olmstead, S. Craig George and Jeffrey R. Olmstead;*
- *initial public offering refers to our December 2011 initial public offering of 5,400,000 of our common units and subsequent over-allotment offering of 810,000 of our common units;*
- *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 Yorktown;*
- *Mid-Con Energy Partners, the partnership, we, our, us or like terms when referring to periods prior to our initial public offering generally refer to our predecessor, which was merged with and into Mid-Con Energy Properties, LLC, our wholly owned subsidiary, in connection with our initial public offering. When used in reference to periods after our initial public offering or prospectively, those terms refer to Mid-Con Energy Partners, LP, a Delaware limited partnership, and its subsidiaries;*
- *Mid-Con Energy Operating refers to our affiliate Mid-Con Energy Operating, Inc.*;
- *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;*
- *Selling Unitholders refers to Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P.; 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.*

We include a glossary of some of the oil and natural gas terms used in this prospectus in Appendix A.

Mid-Con Energy Partners, LP

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 management team has significant industry experience, especially with waterflood projects and, as a result, our operations focus primarily on enhancing the development of

1

producing oil properties through waterflooding. 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, 2011, our total estimated proved reserves were 10.0 MMBoe, of which approximately 99% were oil and 69% were proved developed, both on a Boe basis. As of December 31, 2011, Mid-Con Energy Operating operated 99% of our properties and 96% of our properties were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended June 30, 2012 was approximately 1,844 Boe per day and based on our December 31, 2011 audited reserves, as adjusted for average net production for the six months ended June 30, 2012, our total estimated proved reserves had a reserve-to-production ratio of approximately 15 years. As of December 31, 2011, our management team developed approximately 59% of our total reserves through new waterflood projects.

Our Properties

Our properties are located in the Mid-Continent region of the United States and primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates. Our core areas of operation are located in Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. As of December 31, 2011, approximately 91% of the properties associated with our estimated reserves, on a Boe basis, have been producing continuously since 1982 or earlier. Through the application of waterflooding, we believe these mature properties have attractive upside potential. Waterflooding, a form of secondary oil recovery, works by repressuring a reservoir through water injection and pushing or sweeping oil to producing wellbores. Based on the production estimates from our December 31, 2011 audited reserve report, the average estimated decline rate for our proved developed producing reserves is approximately 8.0% for 2012 and, on a compounded average decline basis, approximately 11% for the subsequent five years and approximately 10% thereafter.

The following table summarizes information by core area regarding our estimated oil and natural gas reserves as of December 31, 2011 and our average net production for the month ended June 30, 2012.

	Estimated Net Proved Reserves as of December 31, 2011				Average Net Production for the Month Ended June 30, 2012			Gross Active Wells as of June 30, 2012		
	(MBoe)	% Operated	% Oil	% Proved Developed	Boe/d Gross	Boe/d Net	Reserve-to-Production Ratio(1)	Oil and Natural Gas Wells	Injection Wells	Shut-in/ Waiting on Completion
Southern Oklahoma	5,528	100%	100%	68%	2,600	1,128	13	79	53	12
Northeastern Oklahoma	3,179	100%	99%	69%	742	447	19	201	76	54
Hugoton Basin	1,060	100%	99%	69%	340	219	13	29	15	13
Other	282	77%	77%	100%	140	50	15	11	5	2
Total	**10,049**	**99%**	**99%**	**69%**	**3,822**	**1,844**	**15**	**320**	**149**	**81**

(1) The reserve-to-production ratio is calculated by subtracting net production for the six months ended June 30, 2012 from estimated net proved reserves as of December 31, 2011 and dividing the result by average net production for the month ended June 30, 2012.

Table of Contents

The following chart summarizes our total average net Boe production volumes on a monthly basis, and illustrates the 47% increase in our production volumes over the twelve months ended June 30, 2012. We achieved this production increase primarily through ongoing waterflood response from existing development activities and from workovers and acquisitions.

Recent Developments

On October 15, 2012, we entered into a Purchase and Sale Agreement to acquire certain oil properties located in our Hugoton Basin core area. The base purchase price for such properties, which is subject to standard adjustments and preference right exercises, is approximately $21 million, which includes a performance deposit of $2.1 million. This acquisition is expected to close on or before November 6, 2012 and will be financed using existing cash and borrowings from our credit facility. This acquisition includes current net production of approximately 175 Boe per day, estimated net proved reserves of approximately 1.3 MMBoe (55% proved developed producing and 99% oil on a Boe basis) and a reserve-to-production ratio of approximately 20 years. We will acquire 14 gross producing, 7 gross injecting and 1 gross water supply well associated with these properties. The estimated proved reserves for this acquisition were based on our preliminary internal evaluation of information provided by the seller and proved reserves as of the acquisition date for the above-referenced acquisition were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that this acquisition will be immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for this property may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Additionally, on October 12, 2012, we entered into an agreement to assign additional working interests in our existing War Party I and II Units located in our Hugoton Basin core area, effective as of April, 2012. Pursuant to the agreement, we will pay approximately $3.5 million for these properties using existing cash and borrowings from our credit facility. As a result of this assignment, we will have 100% and 99% of the working interests in our War Party I and II Units, respectively. The working interests to be assigned include current net production of approximately 83 Boe per day, estimated net proved reserves of approximately 0.5 MMBoe (85% proved developed producing and 99% oil on a Boe basis) and a reserve-to-production ratio of approximately 20 years. The estimated proved reserves for the working interests to be assigned are based on our preliminary internal evaluation of information provided by the seller, and proved reserves as of the effective date for the above-referenced assignment is estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that the working interests included in this assignment will be immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for this property may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Completion of these acquisitions are subject to the satisfaction of customary closing conditions and the waiver of preference rights and obtaining necessary consents from third parties. Failure to satisfy these conditions, if not waived, would prevent us from consummating these acquisitions or the amount of properties we may obtain may be materially reduced, resulting in a proportional decrease in our expected net reserves and production. As a result, we can provide no assurance that these acquisitions will be completed within the anticipated time frame, or at all. The closing of these acquisitions is not conditioned on the closing of this offering, and this offering is not conditioned on the closing of these acquisitions. In the event that we are unable to complete these acquisitions, our approximately $2.1 million deposit we have paid for the Clawson Ranch would potentially be subject to forfeiture.

During June 2012, we acquired certain oil properties located in our Northeastern Oklahoma core area, and additional working interests in our existing units in our Southern Oklahoma core area, in unrelated transactions. We paid approximately $16.4 million in aggregate consideration for these properties. The transactions were financed using existing cash and borrowings from our credit facility. These acquisitions include current net production of approximately 115 Boe per day, estimated net proved reserves of approximately 0.6 MMBoe (53% proved developed producing and 100% oil on a Boe basis) and an average reserve-to-production ratio of approximately 14 years. The estimated proved reserves for these acquisitions were based on our preliminary internal evaluation of information provided by the sellers and proved reserves as of the acquisition date for the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that these acquisitions were immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for these properties may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Table of Contents

Our general partner also declared a cash distribution of $0.485 per unit ($1.94 per unit on an annualized basis) on October 15, 2012 for the third quarter of 2012, which will be paid on November 14, 2012 to unitholders of record at the close of business on November 7, 2012. This is an increase of $0.01 from the previous quarter. Our management also confirmed on October 15, 2012 that our previously released Boe production guidance for the third quarter of 2012 will come in within the previously announced range, likely toward the lower-end.

Our Hedging Strategy

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 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. For the three months ending December 31, 2012 and the years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of our fourth quarter 2012 and 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, 2011). All of our derivative contracts for 2012, 2013 and 2014 are either swaps with fixed settlements or collars. The weighted average minimum prices on all of our derivative contracts for 2012, 2013 and 2014 are $101.59, $99.66 and $94.30, 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.

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 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Derivative Contracts.

Our Business Strategies

Our primary business objective is to manage our oil and natural gas properties for the purpose of generating stable cash flows, which we expect will provide stability and, over time, growth of distributions to our unitholders. In addition to our hedging strategy described above, we intend to execute the following business strategies:

- Continue exploitation of our existing properties to maximize production;
- Pursue acquisitions of long-lived, low-risk producing properties with upside potential;
- Capitalize on our relationship with the Mid-Con Affiliates for favorable acquisition opportunities;

Table of Contents

- Maintain operational control and a focus on cost-effectiveness in all our operations;

- Reduce the impact of commodity price volatility on our cash flow through a disciplined commodity hedging strategy;

- Maintain a balanced capital structure to allow for financial flexibility to execute our business strategies; and

- Utilize compensation programs that align the interests of our management team with our unitholders.

For a more detailed description of our business strategies, please read Business and Properties Our Business Strategies.

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;

- The ability to further exploit existing mature properties by utilizing our waterflooding expertise;

- 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;

- Access to the collective expertise of Yorktown s employees and their extensive network of industry relationships through our relationship with Yorktown;

- Mid-Con Energy Operating operates 99% of our properties, which allows them to control our operating costs and capital expenditures;

- An enhanced ability to pursue acquisition opportunities arising from our competitive cost of capital and balanced capital structure; and

- The range and depth of our technical and operational expertise will allow us to expand both geographically and operationally to achieve our goals.

For a more detailed discussion of our competitive strengths, please read Business and Properties Our Competitive Strengths.

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. Please read Certain Relationships and Related Party Transactions Review, Approval or Ratification of Transactions with Related Persons.

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. Yorktown made several equity investments in our predecessor. Prior to this offering, Yorktown owned an approximate 48.5% limited partner interest in us, making it our largest unitholder. Immediately following this offering, Yorktown will own an approximate 30.1% limited partner interest in us (or an approximate 26.9% limited partner interest in us if the underwriters exercise their option to purchase additional common units in full), and will continue to be our largest unitholder. Yorktown Energy Partners IX, L.P. will continue to own 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, we believe that 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, including the Mid-Con Affiliates, that compete with us.

Risk Factors

An investment in our common units involves risks. Below is a summary of certain key risk factors that you should consider in evaluating an investment in our common units. This list is not exhaustive. Please read the full discussion of these risks and other risks described under Risk Factors.

Risks Related to Our Business

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

- 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.

- 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.

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

Table of Contents

Our business depends in part on transportation, pipelines and refining facilities owned by others. Any limitation in the availability of those facilities, or increase in their costs, could interfere with our ability to market our production and adversely affect our revenues.

Risks Inherent in an Investment in Us

Our general partner controls us, and following this offering, the Founders and Yorktown will own a 36.0% limited partner interest in us, or a 32.8% limited partner interest in us if the underwriters exercise their option to purchase additional common units in full. 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.

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.

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

Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors.

Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

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

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.

Tax Risks to Unitholders

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

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.

Table of Contents

Ownership and Organizational Structure of Mid-Con Energy Partners, LP

The diagram below depicts our organization and ownership after giving effect to the offering and assumes that the underwriters do not exercise their option to purchase additional common units from the Selling Unitholders.

Common units held by the public	53.4%
Common units held by the Founders	5.8%
Common units held by Yorktown	29.5%
Common units held by our executive officers, employees and other individuals and entities, other than the Founders and Yorktown who held membership interests in our predecessor	9.4%
General partner units	1.9%
Total	100.0%

(1) The Founders are S. Craig George, Charles R. Olmstead and Jeffrey R. Olmstead.

(2) Yorktown Energy Partners IX, L.P. owns a 50% interest in Mid-Con Energy Operating. Yorktown IX Company LP is the sole general partner of Yorktown Energy Partners IX, L.P. Yorktown Associates LLC is the sole general partner of Yorktown IX Company LP. Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., and Yorktown Energy Partners VIII, L.P. own common units in us. For more information on the entities that control Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., and Yorktown Energy Partners VIII, L.P., please read Security Ownership of Certain Beneficial Owners and Management.

Table of Contents

Management of Mid-Con Energy Partners, LP

We are managed and operated by the board of directors and executive officers of our general partner, Mid-Con Energy GP, LLC. Our unitholders are not entitled to elect our general partner or its directors or otherwise participate in our management or operation. All of the executive officers of our general partner are also officers and/or directors of the Mid-Con Affiliates. For information about the executive officers and directors of our general partner, please read Management.

S. Craig George, the Executive Chairman of the board of directors of our general partner, Charles R. Olmstead, the Chief Executive Officer and a director of our general partner, and Jeffrey R. Olmstead, the President and Chief Financial Officer and a director of our general partner, each own one-third of the member interests in our general partner. As the holders of all of the member interests of our general partner, the Founders control our general partner, are entitled to appoint its entire board of directors and receive all of the distributions our general partner receives in respect of its approximate 2.0% general partner interest in us. Please read Security Ownership of Certain Beneficial Owners and Management.

Neither we, our general partner, nor our subsidiary have any employees. We and our general partner are parties to a services agreement with Mid-Con Energy Operating, pursuant to which Mid-Con Energy Operating provides management, administrative and operational services to us. Although all of the employees that conduct our business are employed by Mid-Con Energy Operating, we sometimes refer to these individuals in this prospectus as our employees.

We have one subsidiary, Mid-Con Energy Properties, that holds title to our properties.

Principal Executive Offices and Internet Address

Our headquarters are located at 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201. Our principal operating office is located at 2431 East 61st Street, Suite 850, Tulsa, Oklahoma 74136, and our telephone number is (972) 479-5980. Our website address is www.midconenergypartners.com. We make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, which we refer to as the SEC, available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus.

Table of Contents

Summary of Conflicts of Interest and Fiduciary Duties

Under our partnership agreement, our general partner has a legal duty to manage us in a manner that is in, or not opposed to, the best interests of the holders of our common units. This legal duty, as modified by our partnership agreement, originates in statutes and judicial decisions and is commonly referred to as a fiduciary duty. However, the officers and directors of our general partner also have a fiduciary duty to manage the business of our general partner in a manner beneficial to its owners, the Founders. All of the executive officers of our general partner are also officers and/or directors of the Mid-Con Affiliates and have economic interests in the Mid-Con Affiliates. In addition, Peter A. Leidel, a principal of Yorktown, serves on our board of directors. Mr. Leidel has economic interests in Yorktown and its affiliates that manage, hold and own investments in other funds and companies that may compete with us. As a result of these relationships, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its owners and affiliates, on the other hand. For example, our general partner is entitled to make determinations that affect our ability to generate the cash flow necessary to make cash distributions to our unitholders, including determinations related to:

- purchases and sales of oil and natural gas properties and other acquisitions and dispositions, including whether to pursue acquisitions that may also be suitable for the Mid-Con Affiliates, Yorktown or any Yorktown portfolio company;
- the manner in which our business is operated;
- the level of our borrowings;
- the amount, nature and timing of our capital expenditures; and
- the amount of cash reserves necessary or appropriate to satisfy our general, administrative and other expenses and debt service requirements and to otherwise provide for the proper conduct of our business.

For a more detailed description of the conflicts of interest and fiduciary duties of our general partner, please read Risk Factors Risks Inherent in an Investment in Us and Conflicts of Interest and Fiduciary Duties.

Generally, our partnership agreement can be amended in a manner that materially adversely affects our limited partners only with the consent of our general partner and the approval of the holders of a majority of our outstanding common units (including any common units held by affiliates of our general partner). Following this offering, our general partner will continue to be owned by the Founders, and the Founders and Yorktown collectively will own and control the voting of an aggregate of approximately 36.0% of our outstanding common units, or approximately 32.8% of our outstanding common units if the underwriters exercise their option to purchase additional common units in full. Please read Risk Factors Risks Inherent in an Investment in Us and The Partnership Agreement Amendment of the Partnership Agreement.

Partnership Agreement Modification of Fiduciary Duties

Our partnership agreement limits the liability of our general partner and reduces the fiduciary duties it owes to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions that might otherwise constitute a breach of the fiduciary duties that our general partner owes to our unitholders. By purchasing a common unit, our unitholders agree to be bound by the terms of our partnership agreement and, pursuant to the terms of our partnership agreement, are treated as having

Table of Contents

consented to various actions contemplated in our partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary or other duties under Delaware law. Please read Conflicts of Interest and Fiduciary Duties Fiduciary Duties for a description of the fiduciary duties imposed on our general partner by Delaware law, the material modifications of these duties contained in our partnership agreement and certain legal rights and remedies available to our unitholders.

Implication of Being an Emerging Growth Company

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. An emerging growth company may take advantage of specified reduced reporting and other regulatory requirements for up to five years that are otherwise applicable generally to public companies. These provisions include:

- a requirement to present only two years of audited financial statements and only two years of related Management s Discussion and Analysis;
- exemption from the auditor attestation requirement on the effectiveness of our system of internal control over financial reporting;
- exemption from the adoption of new or revised financial accounting standards until they would apply to private companies;
- exemption from compliance with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; and
- reduced disclosure about executive compensation arrangements.

We will cease to be an emerging growth company if we have more than $1.0 billion in annual revenues, have more than $700 million in market value of our limited partner interests held by non-affiliates, or issue more than $1.0 billion of non-convertible debt over a three-year period.

We have elected to take advantage of the applicable JOBS Act provisions, except for the following:

- we have elected to present three years of audited financial statements and three years of related Management s Discussion and Analysis rather than only two years;
- we have elected to opt out of the exemption that allows emerging growth companies to extend the transition period for complying with new or revised financial accounting standards (this election is irrevocable);
- we have elected to comply with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; and
- we have elected to make full disclosure about executive compensation arrangements.

Accordingly, the information that we provide you may be different than what you may receive from other public companies in which you hold equity interests.

Table of Contents

The Offering

Common units offered by us	1,000,000 common units. As described below, if the underwriters exercise their option to purchase additional common units, such units will be offered exclusively by the Selling Unitholders on a pro rata basis.
Common units offered by the Selling Unitholders	3,000,000 common units, or 3,600,000 common units if the underwriters exercise in full their option to purchase additional common units, which in each case will be offered by the Selling Unitholders on a pro rata basis, in proportion to their interests in us.
	Immediately before this offering, Yorktown owned 8,691,468 common units, representing an approximate 48.5% limited partner interest in us. Following this offering, Yorktown will own 5,691,468 common units, or 5,091,468 common units if the underwriters exercise in full their option to purchase additional common units, representing an approximate 30.1% and 26.9% limited partner interest in us, respectively.
Units outstanding after this offering	18,939,549 common units.
Use of proceeds	We intend to use the net proceeds of approximately $20.2 million from this offering, after deducting underwriting discounts and estimated expenses, to repay approximately $20.2 million of indebtedness outstanding under our credit facility.
	We will not receive any proceeds from the sale of common units by the Selling Unitholders, including any proceeds from the sale of common units by the Selling Unitholders if the underwriters exercise in whole or in part their option to purchase additional common units.
	Affiliates of certain of the underwriters are lenders under our credit facility and accordingly, will receive a substantial portion of the proceeds from this offering. Please read Underwriting.
Cash distributions	We paid a quarterly distribution of $0.475 per unit for the second quarter of 2012 on all common and general partner units ($1.90 per unit on an annualized basis) on August 14, 2012 to unitholders of record as of August 7, 2012. Distributions on our units are generally paid approximately 45 days following the end of a fiscal quarter to the extent we have sufficient cash from operations, after the establishment of cash reserves and the payment of fees and expenses.
	There is no guarantee that unitholders will receive a quarterly distribution from us. We do not have a legal obligation to pay

13

Table of Contents

	distributions at our current quarterly distribution rate or at any other rate except as provided in our partnership agreement.
	Assuming our general partner maintains its approximate 2.0% general partner interest in us, our partnership agreement requires that we distribute approximately 98.0% of our available cash each quarter to the holders of our common units, pro rata, and approximately 2.0% to our general partner.
	Unlike many publicly traded limited partnerships, our general partner is not entitled to any incentive distributions, and we do not have any subordinated units.
Issuance of additional units	We can issue an unlimited number of additional units, including units that are senior to the common units in right of distributions, liquidation and voting, on terms and conditions determined by our general partner, without the approval of our unitholders. Please read Units Eligible for Future Sale and The Partnership Agreement Issuance of Additional Interests.
Limited voting rights	Our general partner manages us and operates our business. Unlike stockholders of a corporation, our unitholders have only limited voting rights on matters affecting our business. Our unitholders have no right to elect our general partner or its board of directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least $66^2/_3\%$ of the outstanding units, including any units owned by our general partner and its affiliates. Following this offering, the Founders and Yorktown will own an aggregate of approximately 36.0% of our common units (or approximately 32.8% of our common units if the underwriters exercise their option to purchase additional common units in full) and, therefore, will be able to prevent the removal of our general partner. Please read The Partnership Agreement Limited Voting Rights.
Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a purchase price not less than the then-current market price of the common units, as calculated pursuant to the terms of our partnership agreement. Following this offering, the Founders will own an aggregate of approximately 5.9% of our common units. Please read The Partnership Agreement Limited Call Right.
Eligible Holders and redemption	Units held by persons who our general partner determines are not Eligible Holders will be subject to redemption. As used herein, an Eligible Holder means any person or entity qualified to hold an interest in oil and natural gas leases on federal lands. If, following

Table of Contents

	a request by our general partner, a transferee or unitholder, as the case may be, does not properly complete a recertification for any reason, we will have the right to redeem the units held by such person at the then-current market price of the units held by such person. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. Please read Description of the Common Units Transfer Agent and Registrar Transfer of Common Units and The Partnership Agreement Non-Citizen Unitholders; Redemption.
Estimated ratio of taxable income to distributions	We estimate that if our unitholders own the common units purchased in this offering through the record date for distributions for the period ending December 31, 2014, such unitholders will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than 45% of the cash distributed to such unitholders with respect to that period. Please read Material Tax Consequences Tax Consequences of Unit Ownership Ratio of Taxable Income to Distributions for the basis of this estimate.
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please read Material Tax Consequences.
Listing and trading symbol	Our common units are listed on the NASDAQ Global Market under the symbol MCEP.

Table of Contents

Summary Historical Financial Data

The following table shows summary financial data of us and our predecessor for the periods and as of the dates indicated. The summary financial data as of and for the year ended June 30, 2009 is derived from the audited consolidated financial statements of our predecessor included elsewhere in this prospectus. The summary financial data as of and for the years ended December 31, 2010 and 2011 is derived from our audited consolidated financial statements included elsewhere in this prospectus. The summary financial data as of any for the six months ended December 31, 2009 is derived from our audited Consolidated Statements of Operations and Statements of Cash Flows included elsewhere in this prospectus, except for the balance sheet data which is derived from our audited consolidated balance sheet not included in this prospectus. The summary financial data as of and for the six months ended June 30, 2011 and 2012 is derived from our unaudited consolidated financial statements included elsewhere in this prospectus.

You should read the following table in conjunction with Use of Proceeds, Management s Discussion and Analysis of Financial Condition and Results of Operations, the audited historical consolidated financial statements of Mid-Con Energy Partners, LP and our predecessor and the unaudited consolidated financial statements of Mid-Con Energy Partners, LP and the notes thereto included elsewhere in this prospectus. Among other things, those historical consolidated financial statements and unaudited consolidated financial statements include more detailed information regarding the basis of presentation for the following information.

The following table presents a non-GAAP financial measure, Adjusted EBITDA, which we use in evaluating the financial performance and liquidity of our business. This measure is not calculated or presented in accordance with generally accepted accounting principles, or GAAP. We explain this measure below and reconcile it to the most directly comparable financial measures calculated and presented in accordance with GAAP.

Table of Contents

	Mid-Con Energy Corporation (consolidated)		Mid-Con Energy Partners, LP			
	Year Ended June 30,	Six Months Ended December 31,	Year Ended December 31,		Six Months Ended June 30,	
	2009	2009	2010	2011	2011 (unaudited)	2012 (unaudited)
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil sales	$ 10,246	$ 5,729	$ 16,853	$ 36,813	$ 15,609	$ 28,998
Natural gas sales	2,172	743	1,418	1,218	658	353
Realized gain (loss) on derivatives, net	(669)	(350)	(90)	(2,157)	(715)	769
Unrealized gain (loss) on derivatives, net	1,679	(147)	(707)	3,437	1,046	9,741
Total revenues	13,428	5,975	17,474	39,311	16,598	39,861
Operating costs and expenses:						
Lease operating expenses	5,369	2,431	6,237	8,491	3,550	4,725
Oil and gas production taxes	631	269	822	1,869	656	713
Dry holes and abandonments of unproved properties			1,418	813	772	
Geological and geophysical	507		394	172		
Depreciation, depletion and amortization	2,293	2,552	5,851	7,160	2,418	4,709
Accretion of discount on asset retirement obligations	78	58	127	78	32	57
General and administrative	1,767	704	982	1,924	534	4,869
Impairment of proved oil and gas properties		9,208	1,886			
Total operating costs and expenses	10,645	15,222	17,717	20,507	7,962	15,073
Income (loss) from operations	2,783	(9,247)	(243)	18,804	8,636	24,788
Other income (expenses):						
Interest income and other	118	35	218	216	62	5
Interest expense	(93)	(2)	(98)	(578)	(237)	(703)
Gain on sale of assets	1		354	1,621	1,209	
Equity-based compensation				(1,671)		
Other revenue and expenses, net	298	118	847	576	576	
Tax expense current	(625)					
Tax (expense) benefit deferred	502					
Net income (loss)	$ 2,984	$ (9,096)	$ 1,078	$ 18,968	$ 10,246	$ 24,090
Net income per limited partner unit (basic and diluted)		$ (0.51)	$ 0.06	$ 1.05	$ 0.57	$ 1.33
Weighted average number of limited partner units outstanding (basic and diluted)		17,640	17,640	17,640	17,640	17,790
Other Financial Data:						
Adjusted EBITDA	$ 3,773	$ 2,836	$ 10,593	$ 23,994	$ 11,388	$ 22,503
Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 10,935	$ 965	$ 11,798	$ 24,113	$ 5,192	$ 24,384
Investing activities	(12,448)	(5,018)	(22,726)	(42,045)	(13,351)	(23,992)

Financing activities	4,841	(1,164)	10,387	17,938	8,377	3,344

	Mid-Con Energy Partners, LP				
	As of December 31,			As of June 30,	
	2009	2010	2011	2011 (unaudited)	2012 (unaudited)
	(in thousands)				
Balance Sheet Data:					
Working capital(1)	$ 2,420	$ (1,256)	$ 2,361	$ 4,383	$ 11,879
Total assets	40,496	56,867	96,611	72,390	125,148
Total debt	337	5,513	45,000	13,310	58,000
Total Equity	36,779	43,072	43,349	56,098	60,473

(1) For 2010, excludes $5.3 million of current maturities under our predecessor s credit facilities. The maturity date for these facilities was subsequently extended to December 2013.

18

Table of Contents

Non-GAAP Financial Measures

We include in this prospectus 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, our most directly comparable financial measures calculated and presented in accordance with GAAP. 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 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 cash flow available to pay distributions to our unitholders, develop existing reserves or acquire additional oil properties.

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. 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. The following table presents our reconciliation of Adjusted EBITDA to Net Income. 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.

Table of Contents

Reconciliation of Adjusted EBITDA to Net Income

	Mid-Con Energy Corporation (consolidated)		Mid-Con Energy Partners, LP			
	Year Ended June 30, 2009	Six Months Ended December 31, 2009	Year Ended December 31, 2010	2011	Six Months Ended June 30, 2011 (unaudited)	2012 (unaudited)
			(in thousands)			
Net income (loss)	$ 2,984	$ (9,096)	$ 1,078	$ 18,968	$ 10,246	$ 24,090
Tax expense (benefit) deferred	(502)					
Tax expense current	625					
Interest expense	93	2	98	578	237	703
Depreciation, depletion and amortization	2,293	2,552	5,851	7,160	2,418	4,709
Accretion of discount on asset retirement obligations	78	58	127	78	32	57
Unrealized (gain) loss on derivatives, net	(1,679)	147	707	(3,437)	(1,046)	(9,741)
Impairment of proved oil and gas properties		9,208	1,886			
Dry holes and abandonments of unproved properties			1,418	813	772	
Gain on sale of assets	(1)		(354)	(1,621)	(1,209)	
Equity-based compensation				1,671		2,690
Interest income	(118)	(35)	(218)	(216)	(62)	(5)
Adjusted EBITDA	$ 3,773	$ 2,836	$ 10,593	$ 23,994	$ 11,388	$ 22,503

Reconciliation of Adjusted EBITDA to Net Cash Provided by Operating Activities

	Mid-Con Energy Corporation (consolidated)		Mid-Con Energy Partners, LP			
	Year Ended June 30, 2009	Six Months Ended December 31, 2009	Year Ended December 31, 2010	2011	Six Months Ended June 30, 2011 (unaudited)	2012 (unaudited)
			(in thousands)			
Net cash provided by operating activities	$ 10,935	$ 965	$ 11,798	$ 24,113	$ 5,192	$ 24,384
Amortization of debt placement fees						(54)
Change in working capital	(7,762)	1,904	(1,085)	(481)	6,021	(2,525)
Tax expense current	625					
Interest expense	93	2	98	578	237	703
Interest income	(118)	(35)	(218)	(216)	(62)	(5)
Adjusted EBITDA	$ 3,773	$ 2,836	$ 10,593	$ 23,994	$ 11,388	$ 22,503

Table of Contents

Summary Historical Reserve and Operating Data

The following table presents summary data with respect to our estimated net proved oil and natural gas reserves that we own and the standardized measure amounts associated with those estimated proved reserves as of December 31, 2010 and as of December 31, 2011, both based on reserve reports prepared by our internal reserve engineers and audited by Cawley, Gillespie & Associates, Inc., our independent reserve engineers.

These reserve estimates were prepared in accordance with the SEC s rules regarding oil and natural gas reserve reporting that are currently in effect. From December 31, 2010 to December 31, 2011 our proved reserves increased by approximately 2.8 MMBoe, or 39%. Total proved reserves increased by approximately 0.9 MMBoe from acquisitions in the Hugoton Basin and Northeastern Oklahoma core areas; 0.8 MMBoe from waterflood expansion in the Northeastern Oklahoma core area; 0.7 MMBoe from infill drilling in the Southern Oklahoma core area; 0.7 MMBoe from drilling and workovers in the Northeastern Oklahoma core area and (0.3) MMBoe in net performance revisions for all of our properties. We spent a total of $19.3 million and $30.0 million in capital expenditures for the year ended December 31, 2010 and the year ended December 31, 2011, respectively, which contributed to the increase in our December 31, 2011 proved reserves.

From December 31, 2010 to December 31, 2011 our proved developed reserves increased by approximately 3.1 MMBoe, or 82%. Proved developed reserves increased in our Southern Oklahoma core area by 0.9 MMBoe from development drilling and 0.7 MMBoe in performance revisions; in the Hugoton Basin core area by 0.7 MMBoe from the acquisition of the War Party I and II Units; in our Northeastern Oklahoma core area by 0.2 MMBoe from acquisitions, 0.7 MMBoe from infill drilling and workovers and (0.1) MMBoe in net performance revisions for the Hugoton Basin and Northeastern Oklahoma core areas and other properties.

During the year ended December 31, 2011, we spent approximately $21.9 million in our Southern Oklahoma core area resulting in production increases and reclassifications of 0.9 MMBoe from proved undeveloped reserves to proved developed reserves, which contributed to the 1.6 MMBoe increase in proved developed reserves in our Southern Oklahoma core area discussed in the prior paragraph. Additionally, we spent approximately $13.2 million during the year ended December 31, 2011 to acquire new leases in the Hugoton Basin and Northeastern Oklahoma. We spent another $2.4 million on workover activities and $3.4 million on drilling during the year ended December 31, 2011 in Northeastern Oklahoma.

Table of Contents

For a discussion of risks associated with internal reserve estimates, please read Risk Factors Risks Related to Our Business 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. Please also read Management s Discussion and Analysis of Financial Condition and Results of Operations, Business and Properties Oil and Natural Gas Reserves and Production Estimated Proved Reserves, and the summary of our reserve audits dated December 31, 2010 and December 31, 2011 in evaluating the material presented below.

	As of December 31, 2010	As of December 31, 2011
Reserve Data:		
Estimated proved reserves:		
Oil (MBbl)	7,007	9,936
Natural Gas (MMcf)	1,346	676
Total (MBoe)	7,231	10,049
Proved developed (MBoe)	3,825	6,948
Oil (MBbl)	3,601	6,835
Natural Gas (MMcf)	1,346	676
Proved undeveloped (MBoe)	3,406	3,101
Oil (MBbl)	3,406	3,101
Natural Gas (MMcf)		
Proved developed reserves as a percentage of total proved reserves	52.9%	69.1%
Standardized Measure (in millions)(1)	$ 183.7	$ 328.2
Oil and Natural Gas Prices(2):		
Oil NYMEX WTI per Bbl	$ 79.43	$ 96.19
Natural gas NYMEX Henry Hub per MMBtu	$ 4.37	$ 4.11

(1) Standardized measure is calculated in accordance with Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities, as codified in ASC Topic 932, Extractive Activities Oil and Gas. Because we were not subject to federal or state income taxes for the periods presented, we 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.

(2) Our estimated net proved reserves and related standardized measure were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $79.43 per Bbl for oil and $4.37 per MMBtu for natural gas at December 31, 2010 and $96.19 per Bbl for oil and $4.11 per MMBtu for natural gas at December 31, 2011. 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. For the year ended December 31, 2010, the relevant average realized prices for oil and natural gas were $73.92

Table of Contents

per Bbl and $7.42 per Mcf, respectively. For the year ended December 31, 2011, the relevant average realized prices for oil and natural gas were $90.45 per Bbl and $7.43 per Mcf, respectively. Realized natural gas sales price per Mcf includes the sale of natural gas liquids for both the year ended December 31, 2010 and the year ended December 31, 2011.

	Year Ended December 31, 2011	Six Months Ended June 30, 2012
Production and operating data:		
Net production volumes:		
Oil (MBbls)	407	304
Natural gas (MMcf)	164	60
Total (MBoe)	434	314
Average net production (Boe/d)	1,191	1,725
Average sales price:(1)		
Oil (per Bbl)	$ 90.45	$ 95.39
Natural gas (per Mcf)(2)	$ 7.43	$ 5.88
Average price per Boe	$ 87.63	$ 93.47
Average unit costs per Boe:		
Oil and natural gas production expenses	$ 19.56	$ 15.05
Production taxes	$ 4.31	$ 2.27
General and administrative and other(3)	$ 4.43	$ 15.51
Depreciation, depletion and amortization	$ 15.66	$ 15.00

(1) Prices do not include the effects of derivative cash settlements.

(2) Realized natural gas sales price per Mcf includes the sale of natural gas liquids.

(3) General and administrative expenses include non-cash, equity-based compensation for the six months ended June 30, 2012. We had no non-cash, equity-based compensation expense for the year ended December 31, 2011.

Table of Contents

RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation. Prospective unitholders should carefully consider the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our common units.

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline and our unitholders could lose all or part of their investment.

Risks Related to Our Business

We may not have sufficient cash to pay any 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 any distributions to our unitholders. 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, 2011, the NYMEX WTI oil price ranged from a high of $145.29 per Bbl to a low of $33.87 per Bbl. A significant decrease in commodity prices may cause us to reduce the distributions we pay to our unitholders or to cease paying distributions altogether.

24

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 does not currently 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

Table of Contents

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 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.

We may be unable to sustain our current quarterly distribution rate of $0.475 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;

26

Table of Contents

- 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.

As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may prove inaccurate. For example, if the prices used in our December 31, 2011 reserve report had been $10.00 less per barrel for oil, the standardized measure of our estimated proved reserves, without asset retirement obligations, as of that date would have decreased by $48.0 million, from $328.2 million to $280.9 million.

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

Table of Contents

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 Standards 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;

Table of Contents

- 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 from 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 to a subsidiary of Sunoco Logistics Partners, L.P., or Sunoco Logistics, accounted for approximately 86% of our total sales revenues for the year ended December 31, 2011. In 2012, we entered into crude oil purchase agreements with Enterprise Crude Oil, Inc., or Enterprise, Vitol, Inc., or Vitol, and Coffeyville Resources Refining and Marketing, LLC, or Coffeyville Resources. For the six months ended June 30, 2012, sales to Enterprise, Sunoco Logistics and Vitol accounted for approximately 54%, 37% and 2%, respectively, of our total sales. We do not currently sell any production to Sunoco Logistics. After June 30, 2012, we expect that Vitol and Coffeyville Resources will each account for significantly higher percentages of our total sales. Our production is and will continue to be marketed by our affiliate, Mid-Con Energy Operating, under these crude oil purchase contracts. To the extent that any of our current purchasers reduce the volumes 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 Enterprise, Vitol, Coffeyville Resources or any of our other 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 may be unable to compete effectively with larger companies, which may 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.

Table of Contents

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 quarterly 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 will be 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 reaffirmed the borrowing base at $100.0 million on September 20, 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

Table of Contents

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 as 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 one that requires a reduction in emissions of GHGs from motor vehicles and another which requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. On May 12, 2010, the EPA also issued a new tailoring rule, which makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the Clean Air Act. On September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. In addition, on November 30, 2010, the EPA published a final rule that expands its existing GHG emissions reporting rule to include certain owners and operators of onshore oil and natural gas production to monitor GHG emissions beginning in 2011 and to report those emissions beginning in 2012. 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.

Table of Contents

Strict, joint and several liability 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.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, enacted in July 2010, establishes a new regulatory framework for derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on a derivative clearing organization and traded on an exchange or a swap execution facility, and cash collateral will have to be posted. The Dodd-Frank Act requires the Commodities Futures Trading Commission, or the CFTC, federal regulators of banks and other financial institutions, or the Prudential Regulators, and the SEC to promulgate the rules implementing the Dodd-Frank Act, within 360 days from the date of enactment. The CFTC 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. The CFTC s position limits rules will become effective on October 12, 2012, although there is a pending legal proceeding seeking to enjoin those rules. The rules will impose certain position limits for spot month positions; at this time the CFTC has not established limits for non-spot month or combined month positions. Certain CFTC reporting and recordkeeping rules will become effective beginning October 12, 2012, for swap dealer entities. End user compliance with reporting rules and permanent recordkeeping rules is expected to begin 180 days after October 12, 2012.

Depending on the rules and definitions ultimately adopted by the CFTC, the SEC and the Prudential Regulators, we might in the future be required to post cash collateral for our commodities derivative transactions. Posting of cash collateral could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures or other partnership purposes. A requirement to post cash collateral could therefore reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows. We are at risk until the regulators adopt rules and definitions that confirm that companies like us are not required to post cash collateral for our derivative hedging contracts. Even if we are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Dodd-Frank Act s new requirements, and the costs of their compliance will likely be passed on to customers, including us, thus decreasing the benefits to us of hedging transactions and reducing the profitability of our cash flows. In addition, the Dodd-Frank Act may also require our contractual counterparties to our derivative contracts to spin-off their derivative activities to a separate entity, which may not be as creditworthy as the current counterparty. These changes might not only increase costs, but could also reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or reduce our ability to monetize or restructure our existing derivative contracts and potentially increase our exposure to less creditworthy counterparties.

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

Table of Contents

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 begun the process of drafting 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. 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 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. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation 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, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA recently 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. In addition, 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. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing and the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. 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

In addition to the risk factors presented below, there are other risk factors related to conflicts of interests and our general partner s fiduciary duties inherent in an investment in us. See Conflicts of Interest and Fiduciary Duties for a discussion of those risks.

Table of Contents

Our general partner controls us, and immediately following this offering, the Founders and Yorktown will own an approximate 36.0% limited partner interest in us, or an approximate 32.8% in us if the underwriters exercise in full their option to purchase additional common units. 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. Immediately following this offering, the Founders and Yorktown will own an approximate 36.0% limited partner interest in us, or an approximate 32.8% limited partner interest in us if the underwriters exercise in full their option to purchase additional common units. 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 partner s liability, reduces its fiduciary duties and also restricts the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders are consenting to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;

- Neither our partnership agreement nor any other agreement requires the Mid-Con 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 also provides these services to the Mid-Con Affiliates;

- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

Table of Contents

- 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 has limited 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.

Please read Certain Relationships and Related Party Transactions and Conflicts of Interest and Fiduciary Duties.

Our partnership agreement limits our general partner s fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, which allows our general partner to consider only the interests and factors that it desires, without a duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, the exercise of its rights to transfer or vote the units it owns and its determination whether or not to consent to any merger or consolidation involving us or to any amendment to the partnership agreement;

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith;

- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner acting in good faith and not involving a vote of unitholders must either be (i) on terms no less favorable to us than those generally being provided to or available from unrelated third parties or (ii) must be fair and reasonable to us, as determined by our general partner in good faith. In determining whether a transaction or resolution is fair and reasonable, our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- provides that in resolving conflicts of interest, it will be presumed that in making its decision our general partner s board of directors or the conflicts committee of our general partner s board of

Table of Contents

directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

By purchasing a common unit, a unitholder is bound by the provisions in the partnership agreement, including the provisions discussed above.

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 also 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;

Table of Contents

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. Please read Description of the Common Units Transfer Agent and Registrar Transfer of Common Units and The Partnership Agreement Non-Citizen Unitholders; Redemption.

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 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. Please read Management Management of Mid-Con Energy Partners, LP and Certain Relationships and Related Party Transactions. Unlike publicly traded corporations, we do not conduct annual meetings of our unitholders to elect directors or address other matters routinely handled 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, they cannot remove our general partner without its consent.

The public unitholders are currently unable to remove our general partner without its consent because affiliates of our general partner and Yorktown own sufficient units to prevent the removal of 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. Immediately following this offering, the Founders and Yorktown will own approximately 36.0% of our outstanding common units, or approximately 32.8% of our outstanding common units if the underwriters exercise in full their option to purchase additional common units, which will enable those holders, collectively, to prevent the removal of our general partner.

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

Our general partner may transfer its general partner 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

Table of Contents

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 significant unitholders may have an adverse impact on the trading price of our common units.

Following this offering, the Founders and Yorktown will own 6,816,660 common units or approximately 36.0% of our outstanding common units, or 6,216,660 common units or approximately 32.8% of our outstanding common units if the underwriters exercise their option to purchase additional common units in full. Sales of these units or of other substantial amounts of our common units in the public market 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.

Table of Contents

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.

Please read The Partnership Agreement Limited Liability for a discussion of the implications of the limitations of liability on a unitholder.

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 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 thinly traded on the public market. We do not know how liquid the trading market for our common units will be after this offering. 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.

If our common unit price declines, our unitholders could lose a significant part of their investment.

The market price of our common units is subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in commodity prices;

- changes in interest rates;

- changes in securities analysts recommendations and their estimates of our financial performance;

Table of Contents

- public reaction to our press releases, announcements and filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of oil and natural gas companies and securities of publicly traded limited partnerships and limited liability companies;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other oil and natural gas companies;
- variations in the amount of our quarterly cash distributions to our unitholders;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our 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.

Table of Contents

Tax Risks to Unitholders

In addition to reading the following risk factors, prospective unitholders should read Material Tax Consequences for a more complete discussion of the expected material federal income tax consequences of owning and disposing of our units.

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the 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 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.

Table of Contents

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 conclusions of our counsel expressed in this prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not agree with some or all of our counsel s conclusions or 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 those 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 their 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 IDC recapture. In addition, because the amount realized may include a unitholder s share of our nonrecourse liabilities, they may incur a tax liability in excess of the amount of cash they receive from the sale. Please read Material Tax Consequences Disposition of Units Recognition of Gain or Loss.

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, or 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 returns. Please read Material Tax Consequences Tax Consequences of Unit Ownership Section 754 Election for a further discussion of the effect of the depreciation, depletion and amortization positions we will adopt.

We will 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 will 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. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Andrews Kurth LLP has not rendered an opinion with respect to whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations. Please read Material Tax Consequences Disposition of Units Allocations Between Transferors and Transferees.

A unitholder whose units are loaned to a short seller to effect 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. Andrews Kurth LLP has not rendered an opinion regarding the treatment of a unitholder

Table of Contents

where units are loaned to a short seller to effect a short sale of units; therefore, 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. Please read Material Tax Consequences Disposition of Units Constructive Termination for a discussion of the consequences of our termination for federal income tax purposes.

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 likely will 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. Andrews Kurth LLP has not rendered an opinion on the state or local tax consequences of an investment in our units.

Table of Contents

USE OF PROCEEDS

We intend to use the estimated net proceeds of approximately $20.2 million from our sale of common units in this offering, after deducting underwriting discounts and estimated offering expenses, to repay approximately $20.2 million of indebtedness outstanding under our credit facility. Borrowings under our credit facility were used for short-term working capital needs and acquisitions. The borrowings bear interest at approximately 2.5%, and are due upon the expiration of our credit facility in December 2016.

Affiliates of RBC Capital Markets, LLC and Wells Fargo Securities, LLC are lenders under our credit facility, and, accordingly, will receive a substantial portion of the net proceeds from this offering. Please read Underwriting.

We will not receive any of the proceeds from the sale of common units by the Selling Unitholders, including any common units sold by the Selling Unitholders if the underwriters exercise their option to purchase additional common units, in whole or in part.

Table of Contents

CAPITALIZATION

The following table shows our:

historical capitalization as of June 30, 2012; and

as adjusted capitalization as of June 30, 2012, which gives effect to this offering and the application of the net proceeds from this offering as described under Use of Proceeds.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, our historical and unaudited financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations.

	As of June 30, 2012	
	Actual	As Adjusted
	(in thousands)	
Cash and cash equivalents	$ 3,964	$ 3,964
Long-term debt	$ 58,000	$ 37,800
Equity:		
General partner interest	1,638	1,595
Total partners equity	60,473	80,673
Total capitalization	$ 118,473	$ 118,473

47

Table of Contents

PRICE RANGE OF COMMON UNITS AND DISTRIBUTION

Our common units are listed and traded on the NASDAQ Global Market under the symbol MCEP. Our common units began trading on December 15, 2011 at an initial public offering price of $18.00 per common unit. As reported by the NASDAQ Global Market, the following table shows the low and high sales prices per common unit for the periods indicated. Distributions are shown in the quarter for which they were paid:

	Low	High	Cash distribution per unit
2012:			
Fourth quarter (through October 12, 2012)	$ 21.67	$ 22.84	$ (2)
Third quarter	$ 20.31	$ 24.12	$ 0.485(3)
Second quarter	$ 17.87	$ 24.66	$ 0.475
First quarter	$ 18.25	$ 25.18	$ 0.475
2011:			
Fourth quarter(1)	$ 17.25	$ 18.87	$ 0.057(4)

(1) From December 15, 2011, the day our common units began trading on the NASDAQ Global Market, through December 31, 2011.

(2) The distribution payable for the fourth quarter of 2012 has not been declared or paid.

(3) On October 15, 2012, our general partner declared a cash distribution of $0.485 per unit ($1.94 per unit on an annualized basis) for the third quarter of 2012, an increase of $0.01 from the previous quarter, which will be paid on November 14, 2012 to unitholders of record at the close of business on November 7, 2012.

(4) Reflects the pro rata portion of the $0.475 quarterly distribution per unit paid, representing the period from the day after the December 20, 2011 closing of our initial public offering through December 31, 2011. An identical cash distribution was paid on all outstanding common and general partner units.

The last reported sale price of our common units on the NASDAQ Global Market on October 12, 2012 was $22.84. As of October 11, 2012, there were approximately 25 holders of record of our common units. This number does not include owners for whom common units may be held in street name or whose common units are restricted.

Table of Contents

SELECTED HISTORICAL 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 as of and for the years ended June 30, 2007 and 2008 is derived from the audited consolidated financial statements of our predecessor not included in this prospectus. The selected financial data as of and for the year ended June 30, 2009 is derived from the audited consolidated financial statements of our predecessor included elsewhere in this prospectus. The selected financial data as of and for the years ended December 31, 2010 and 2011 is derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected financial data as of and for the six months ended December 31, 2009 is derived from our audited Consolidated Statements of Operations and Statements of Cash Flows included elsewhere in this prospectus except for the balance sheet data which is derived from our audited consolidated balance sheet not included in this prospectus. The selected financial data for the six months ended June 30, 2011 and 2012 is derived from our unaudited consolidated financial statements. The selected financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations, the historical consolidated financial statements of Mid-Con Energy Partners, LP and our predecessor and the unaudited condensed financial statements of Mid-Con Energy Partners, LP and the notes thereto included elsewhere in this prospectus.

The following table represents a non-GAAP financial measure, Adjusted EBITDA, which we use in evaluating the financial performance and liquidity of our business. This measure is not calculated or presented in accordance with GAAP. We explain this measure below and reconcile it to the most directly comparable financial measures calculated and presented in accordance with GAAP.

	Mid-Con Energy Corporation (consolidated)			Mid-Con Energy Partners, LP				
	Year Ended June 30,			Six Months Ended December 31,	Year Ended December 31,		Six Months Ended June 30,	
Statement of Operations Data:	**2007**	**2008**	**2009**	**2009**	**2010**	**2011**	**2011 (unaudited)**	**2012 (unaudited)**
					(in thousands)			
Revenues:								
Oil sales	$ 6,944	$ 13,667	$ 10,246	$ 5,729	$ 16,853	$ 36,813	$ 15,609	$ 28,998
Natural gas sales	64	618	2,172	743	1,418	1,218	658	353
Realized gain (loss) on derivatives, net	558	(804)	(669)	(350)	(90)	(2,157)	(715)	769
Unrealized gain (loss) on derivatives, net	45	(2,035)	1,679	(147)	(707)	3,437	1,046	9,741
Total revenues	7,611	11,446	13,428	5,975	17,474	39,311	16,598	39,861
Operating costs and expenses:								
Lease operating expenses	3,429	5,005	5,369	2,431	6,237	8,491	3,550	4,725
Oil and gas production taxes	478	946	631	269	822	1,869	656	713
Dry holes and abandonments of unproved properties	220				1,418	813	772	
Geological and geophysical	342	1,296	507		394	172		
Depreciation, depletion and amortization	924	1,599	2,293	2,552	5,851	7,160	2,418	4,709
Accretion of discount on asset retirement obligations	35	56	78	58	127	78	32	57
General and administrative	1,805	1,871	1,767	704	982	1,924	534	4,869
Impairment of proved oil and gas properties				9,208	1,886			
Total operating costs and expenses	7,233	10,773	10,645	15,222	17,717	20,507	7,962	15,073
Income (loss) from operations	378	673	2,783	(9,247)	(243)	18,804	8,636	24,788

Table of Contents

Statement of Operations Data:	Mid-Con Energy Corporation (consolidated) Year Ended June 30, 2007	2008	2009	Six Months Ended December 31, 2009	Mid-Con Energy Partners, LP Year Ended December 31, 2010	2011	Six Months Ended June 30, 2011 (unaudited)	2012 (unaudited)
					(in thousands)			
Other income (expenses):								
Interest income and other	126	115	118	35	218	216	62	5
Interest expense	(11)	(3)	(93)	(2)	(98)	(578)	(237)	(703)
Gain on sale of assets			1		354	1,621	1,209	
Equity-based compensation						(1,671)		
Other revenue and expenses, net	439	108	298	118	847	576	576	
Tax expense current			(625)					
Tax (expense) benefit deferred	(197)	(261)	502					
Net income (loss)	$ 735	$ 632	$ 2,984	$ (9,096)	$ 1,078	$ 18,968	$ 10,246	$ 24,090
Net income per limited partner unit (basic and diluted)				$ (0.51)	$ 0.06	$ 1.05	$ 0.57	$ 1.33
Weighted average number of limited partner units outstanding (basic and diluted)				17,640	17,640	17,640	17,640	17,790
Other Financial Data:								
Adjusted EBITDA		$ 4,471	$ 3,773	$ 2,836	$ 10,593	$ 23,994	$ 11,388	$ 22,503
Cash Flow Data:								
Net cash provided by (used in):								
Operating activities	$ 2,052	$ 4,221	$ 10,935	$ 965	$ 11,798	$ 24,113	$ 5,192	$ 24,384
Investing activities	(11,143)	(7,646)	(12,448)	(5,018)	(22,726)	(42,045)	(13,351)	(23,992)
Financing activities	9,980	147	4,841	(1,164)	10,387	17,938	8,377	3,344

Balance Sheet Data:	Mid-Con Energy Partners, LP As of December 31, 2009	2010	2011	As of June 30, 2011	2012
Working capital(1)	$ 2,420	$ (1,256)	$ 2,361	$ 4,383	$ 11,879
Total assets	40,496	56,867	96,611	72,390	125,148
Total debt	337	5,513	45,000	13,310	58,000
Equity	36,779	43,072	43,349	56,098	60,473

(1) For 2010, excludes $5.3 million of current maturities under our predecessor s credit facilities. The maturity date for these facilities was subsequently extended to December 2013.

Table of Contents

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 the Selected Historical Financial Data and the accompanying financial statements and related notes included elsewhere in this prospectus.

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 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. 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, 2011, our total estimated proved reserves were approximately 10.0 MMBoe, of which approximately 99% were oil and 69% were proved developed, both on a Boe basis. As of December 31, 2011, Mid-Con Energy Operating operated 99% of our properties and 96% were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended June 30, 2012 was approximately 1,844 Boe per day and based on our December 31, 2011 audited reserves, as adjusted for average net production for the six months ended June 30, 2012, our total estimated proved reserves had a reserve-to-production ratio of approximately 15 years. As of December 31, 2011, our management team developed approximately 59% of our total reserves through new waterflood projects.

How We Evaluate Our Operations

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.

Production Volumes

Production volumes directly impact our results of operations. For more information about our production volumes, please read Historical Financial and Operating Data.

The following table presents production volumes for our properties for the years ended December 31, 2010 and 2011 and for the six months ended June 30, 2011 and 2012.

	Year Ended December 31,		Six Months Ended June 30,	
	2010	2011	2011	2012
Oil (MBbls)	228	407	167	304

Natural Gas (MMcf)	191	164	79	60
Total (MBoe)	260	434	180	314
Average Net Production (Boe/d)	710	1,191	994	1,725

Table of Contents

Realized Prices on the Sale of Oil

Factors Affecting the Sales Price of Oil. The price of oil generally is determined by factors impacting global and regional supply and demand dynamics, such as economic conditions, production levels, weather cycles and other events. Oil prices are also heavily influenced by product quality and location relative to consuming and refining markets. The NYMEX-WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX-WTI price as a result of quality and location differentials.

Quality differentials to NYMEX-WTI prices result from the fact that oil can differ in its molecular makeup, which plays an important part in its refining and subsequent sale as petroleum products. The two primary characteristics that account for quality differentials are: (1) the oil s American Petroleum Institute, or API, gravity and (2) the oil s percentage of sulfur content by weight. In general, lighter oil (with higher API gravity) produces a larger number of lighter products, such as gasoline, which have higher resale value, and therefore, normally sells at a higher price than heavier oil. Oil with low sulfur content or sweet oil is less expensive to refine and, as a result, normally sells at a higher price than high sulfur-content oil or sour oil. The oil produced from our properties is predominately light sweet oil.

Location differentials to NYMEX-WTI prices result from variances in transportation costs based on the produced oil s proximity to the major trading, transportation and refining markets to which it is ultimately delivered. Oil that is produced close to major trading, transportation and refining markets, such as Cushing, Oklahoma, command a higher price because of lower transportation costs as compared to oil that is produced farther from such markets. Consequently, oil that is produced close to major trading, transportation and refining markets normally realizes a higher price (*i.e.*, a lower location differential to NYMEX-WTI).

Sales Contracts. For the six months ended June 30, 2012, sales to Enterprise, Sunoco Logistics and Vitol accounted for approximately 54%, 37% and 2%, respectively, of our total sales. We enter into six month crude oil purchase agreements with each of our purchasers with month-to-month extensions until either party terminates the contract with a thirty day notice. We believe this allows us to obtain favorable and more predictable pricing for our production than would otherwise be available to us if smaller amounts of our production had been sold to several purchasers based on posted prices.

Our purchase agreements with our purchasers all provide a fixed NYMEX-WTI differential for all production from an individual producing lease. Settlement under all of these purchase agreements occurs monthly, with payment being made on or about the 20th of each month for oil delivered during the previous month. The ultimate price per barrel paid to us by our purchasers is based on a daily average settling price of the near month NYMEX-WTI light sweet crude oil contract during the month in which the oil is actually delivered, minus the applicable differential.

We will continue to compare the pricing under our crude oil purchase contracts to offers from other purchasers to determine the best price in the relevant market.

Commodity Derivative Contracts. To better manage oil price fluctuations and achieve more predictable cash flow, we maintain a portfolio of hedge contracts to help protect our ability to make distributions. These instruments limit our exposure to declines in prices, but also limit our upside if prices increase. Because the prices at which we sell a substantial majority of our oil production are determined by the NYMEX-WTI futures price, our derivatives contract pricing strategy is intended to manage and reduce our exposure to NYMEX-WTI price fluctuations, and is not dependent upon or influenced by the portion of our production we sell to any of our customers.

For the three months ending December 31, 2012 and the years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of our fourth quarter 2012 and 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, 2011). All of our derivative contracts for 2012, 2013 and 2014 are either swaps with fixed settlements or collars. The weighted average minimum prices on all of our derivative contracts for 2012, 2013 and 2014 are $101.59, $99.66 and $94.30, respectively.

The following table reflects, with respect to our existing commodity derivative contracts, the volumes our production covered by commodity derivative contracts and the average prices at which the production will be hedged:

	Six Months Ended December 31, 2012	Year Ended December 31, 2013	2014
Oil Derivative Contracts:			
Swap Contracts:			
Volume (Bbls/d)	1,207	1,216	1,315
Weighted Average NYMEX-WTI price per Bbl	$ 101.85	$ 100.14	$ 94.30
Put/Call Option Contracts (Collars):			
Volume (Bbls/d)	196	296	
Weighted Average Floor-Ceiling NYMEX-WTI price per Bbl	$ 100.00 $117.00	$ 97.67 108.08	$

Lease Operating Expenses

Lease operating expenses are the costs incurred in the operation of producing properties and workover costs. Expenses for utilities, direct labor, water injection and disposal, and materials and supplies comprise the most significant portion of our lease operating expenses. Lease operating expenses do not include general and administrative costs, but do include ad valorem taxes. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased lease operating expenses during the time which they are performed.

A majority of our operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. For example, we incur power costs in connection with various production related activities such as pumping to recover oil, separation and treatment of water produced in connection with our oil production, and re-injection of water into the oil producing formation to maintain reservoir pressure. As these costs are driven not only by volumes of oil produced but also by volumes of water produced, fields that have a high percentage of water production relative to oil production, also known as a high water cut, will experience higher power costs for each barrel of oil produced. Since a majority of our oil is produced from waterflooding, the amount of water produced will increase for a given volume of oil production over the life of these fields. In newly implemented waterflood projects, per unit lifting costs increase early in the life of the project due to production losses associated with the conversion of producing wells to water injection and the additional cost of injecting water. Once production response to injection occurs, the per unit lease operating expenses will begin to decrease as absolute costs remain relatively stable and production rates increase.

An example of decreasing per unit lease operating expenses is our Highlands Unit, where operating costs increased on an absolute basis during the twelve months ended June 30, 2012. During the same twelve month period, per unit lease operating expenses for our Highlands Unit decreased from approximately $16.41 per Boe, for the twelve months ending June 30, 2011, to $9.47 per Boe for the twelve months ended

Table of Contents

June 30, 2012 as production increased due to ongoing response to waterflooding and development drilling. After a waterflood project has reached peak production, the water cut will usually increase, resulting in the production of each barrel of oil becoming more expensive until, at some point, additional production becomes uneconomic.

We typically evaluate our lease operating expenses on a per Boe basis. This allows us to monitor these costs in certain fields and geographic areas to identify trends and to benchmark against other producers. For mature waterflood projects, total lease operating expenses may remain relatively stable, but due to production declines, lease operating expenses will generally increase on a per Boe basis. We believe that one of our areas of core expertise lies in reducing per unit lease operating expenses for mature high water cut waterfloods. We monitor our operations to ensure that we are incurring operating costs at the optimal level relative to our production. Accordingly, we monitor our lease operating expenses and operating costs per well to determine if any wells or properties should be shut in, recompleted or sold.

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 abandonment 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 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.

Adjusted EBITDA should not be considered an alternative to net income, operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. 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. For

Table of Contents

further discussion of the non-GAAP financial measure Adjusted EBITDA, please read Prospectus Summary Non-GAAP Financial Measures.

Outlook

Beginning in the second half of 2008, the United States and other industrialized countries experienced a significant economic slowdown, which led to a substantial decline in worldwide energy demand. While oil prices have generally increased since the second quarter of 2009, the demand for oil remains mixed in foreign markets, especially in China, and the outlook and timing for a worldwide economic recovery remains uncertain for the foreseeable future and the timing of a recovery in worldwide demand for energy to pre-2008 levels is difficult to predict. As a result, it is likely that commodity prices will continue to be volatile in 2012. 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. Significant factors that may impact future commodity prices include the political and economic developments currently impacting North Africa and the Middle East in general, the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to continue to manage oil supply through export quotas, and the overall North American oil and natural gas supply fundamentals.

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 primarily on adding reserves through improving the economics of producing oil from our existing fields and, secondarily, through acquisitions of additional proved reserves. We expect that acquisition opportunities may come from the Mid-Con Affiliates and also from unrelated third parties. 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.

Table of Contents

Historical Financial and Operating Data

The following table sets forth selected historical combined financial and operating data for us and our predecessor for the periods presented. The following table should be read in conjunction with Selected Historical Financial Data.

	Mid-Con Energy Corporation (consolidated)	Mid-Con Energy Partners, LP				
	Year Ended June 30, 2009	Six Months Ended December 31, 2009	Year Ended December 31, 2010	2011	Six Months Ended June 30, 2011 (unaudited)	2012 (unaudited)
			(in thousands)			
Revenues (in thousands):						
Oil sales	$ 10,246	$ 5,729	$ 16,853	$ 36,813	$ 15,609	$ 28,998
Natural gas sales	2,172	743	1,418	1,218	658	353
Realized gain (loss) on derivatives, net	(669)	(350)	(90)	(2,157)	(715)	769
Unrealized gain (loss) on derivatives, net	1,679	(147)	(707)	3,437	1,046	9,741
Total Revenues	$ 13,428	$ 5,975	$ 17,474	$ 39,311	$ 16,598	$ 39,861
Expenses (in thousands):						
Lease operating expense	$ 5,369	$ 2,431	$ 6,237	$ 8,491	3,550	$ 4,725
Oil and gas production taxes	631	269	822	1,869	656	713
Dry holes and abandonments of unproved properties			1,418	813	772	
Depreciation, depletion and amortization(1)	2,103	2,357	5,204	6,795	2,080	4,709
General and administrative(3)	1,767	704	982	1,924	534	4,869
Impairment of proved oil and gas properties		9,208	1,886			
Interest expense	93	2	98	578	237	703
Production:						
Oil (MBbls)	153	87	228	407	167	304
Natural gas (MMcf)	341	140	191	164	79	60
Total (MBoe)	210	110	260	434	180	314
Average net production (Boe/d)	575	602	710	1,191	994	1,725
Average sales price:						
Oil (per Bbl):						
Sales price	$ 66.87	$ 65.85	$ 73.92	$ 90.45	$ 93.47	$ 95.39
Effect of realized commodity derivative instruments	$ (4.37)	$ (4.02)	$ (0.39)	$ (5.30)	$ (4.28)	$ 2.53
Realized price	$ 62.50	$ 61.83	$ 73.53	$ 85.15	$ 89.19	$ 97.92
Natural gas (per Mcf):						
Sales price(2)	$ 6.37	$ 5.31	$ 7.42	$ 7.43	$ 8.33	$ 5.88
Average unit costs per Boe:						
Lease operating expenses	$ 25.56	$ 22.10	$ 23.99	$ 19.56	$ 19.72	$ 15.05
Oil and gas production taxes	$ 3.00	$ 2.45	$ 3.16	$ 4.31	$ 3.64	$ 2.27
General and administrative expenses	$ 8.41	$ 6.40	$ 3.78	$ 4.43	$ 2.97	$ 15.51
Depreciation, depletion and amortization	$ 10.01	$ 21.43	$ 20.02	$ 15.66	$ 11.56	$ 15.00

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

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

(3) General and administrative expenses include non-cash, equity-based compensation for the six months ended June 30, 2012. We had no non-cash, equity based compensation expense for the year ended December 31, 2011.

Results of Operations

Factors Impacting the Comparability of Our Financial Results

The comparability of our future results of operations to our historical results of operations and the comparability of our historical results of operations among the periods presented may be impacted by:

- Our initial public offering of 5,400,000 common units and subsequent over-allotment offering of 810,000 common units in December 2011 and January 2012, respectively;

- The drilling of 35 wells in 2010, 48 wells in 2011 and 14 wells during the six months ended June 30, 2012 on our properties in Oklahoma;

- 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 on June 30, 2011;

- 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;

- The unitization of the Ardmore and Twin Forks Units in January 2009;

- The reorganization of Mid-Con Energy Corporation into two limited liability companies in June 2009, which eliminated our corporate tax expense, and in connection therewith, the change in our fiscal year end from June 30 to December 31;

- Our acquisition in December 2011 of additional working interests in the Cushing Field for $6.0 million; and

- The acquisition in June 2012 of certain oil properties located in our Northeastern Oklahoma core area and additional working interests in our existing units in our Southern Oklahoma core area.

Six Months Ended June 30, 2012 Compared to the Six Months Ended June 30, 2011

Sales Revenues. Revenues from oil and natural gas sales for the six months ended June 30, 2012 were approximately $29.4 million as compared to approximately $16.3 million for the six months ended June 30, 2011. The increase in revenues was primarily due to an increase in daily oil production in 2012.

Our production volumes for the six months ended June 30, 2012 were 314 MBoe, or 1,725 Boe per day. In comparison, our production volumes for the six months ended June 30, 2011 were 180 MBoe, or 994 Boe per day. The increase in production volumes was primarily due to ongoing waterflood response to injection as well as the drilling programs in our Southern Oklahoma core area, and the acquisitions of interests in various properties located in the Hugoton Basin area, which both occurred during the second half of 2011. Our average sales price per barrel for oil, excluding commodity derivative contracts, for the six months ended June 30, 2012 was $95.39, compared with $93.47 for the six months ended June 30, 2011.

Effects of Commodity Derivative Contracts. Due to changes in commodity prices, we recorded a net gain from our commodity hedging program for the six months ended June 30, 2012 of approximately $10.5 million, which was composed of a realized gain of approximately $0.8 million and an unrealized gain of approximately $9.7 million. For the six months ended June 30, 2011, we recorded a net gain from our commodity hedging program of approximately $0.3 million, which was composed of a realized loss of approximately $0.7 million and an unrealized gain of approximately $1.0 million.

Lease Operating Expenses. Our lease operating expenses were $4.7 million for the six months ended June 30, 2012, or $15.05 per Boe, compared to $3.6 million for the six months ended June 30, 2011, or approximately $19.72 per Boe. The increase in total lease operating expenses during the six months ended June 30, 2012 was primarily attributable to an increase in production resulting from our drilling programs and the increase in the number of producing wells. The decrease in lease operating expenses per Boe was due to the increased production for the six months ended June 30, 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 $0.7 million for the six months ended June 30, 2012, or $2.27 per Boe for an effective tax rate of 2.4%, compared to $0.7 million for the six months ended June 30, 2011, or $3.64 per Boe for an effective tax rate of approximately 4.0%. The decrease in the production taxes per Boe during the six months ended June 30, 2012 was primarily due to receiving an adjustment of $0.5 million of production taxes for one of our Southern Oklahoma units for periods prior to the year 2012. The adjustment was due to the Enhanced Recovery Project Gross Production Tax Exemption. 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%. A portion of our wells in Oklahoma continue to receive a reduced production rate due to Oklahoma s Enhanced Recovery Project Gross Production Tax Exemption which has been extended to July 2014.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses on producing properties for the six months ended June 30, 2012 were $4.7 million, or $15.00 per Boe produced, compared to $2.1 million, or $11.56 per Boe produced, for the six months ended June 30, 2011. The increase in depreciation, depletion and amortization expenses and average price per Boe produced was primarily due to the increase in total proved and proved developed reserves estimated at June 30, 2012 and also the increase in total asset value of $40.0 million from our drilling program that occurred in the second half of 2011, and acquisitions of properties in our Hugoton Basin and Southern Oklahoma core areas, which both occurred during the second half of 2011.

General and Administrative Expenses. Our general and administrative expenses were approximately $4.9 million for the six months ended June 30, 2012, or $15.51 per Boe produced compared to approximately $0.5 million for the six months ended June 30, 2011 or $2.97 per Boe produced. The increase in general and administrative expenses for the six months ended June 30, 2012 is primarily due to higher compensation costs related to our non-cash equity-based compensation expense of $2.7 million, higher professional fees necessary to comply with public reporting requirements and incremental costs related to the hiring of additional staff.

Table of Contents

Interest Expense. Our interest expense for the six months ended June 30, 2012 was $0.7 million, compared to $0.2 million for the six months ended June 30, 2011. The increase was primarily due to increased borrowings under our credit facility.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

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 to injection, and the drilling programs in our Oklahoma waterflood units in addition to the acquisition 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 $2.2 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, to injection and an 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 were 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 received 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 on an overall and a decrease on a per Boe produced basis was primarily due to the substantial increase in proved developed reserves estimated at December 31, 2011, in addition to the acquisition of waterflood units in our Hugoton Basin and Southern Oklahoma core areas.

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 $1.9 million for the twelve months ended December 31, 2011, or $4.43 per Boe produced compared to $1.0 million for the twelve months ended December 31, 2010 or $3.78 per Boe produced. The increase in general and administrative expenses for the twelve months ended December 31, 2011 resulted primarily from higher professional fees of approximately $0.5 million and higher personnel costs of approximately $0.4 million. Professional fees included costs related to the preparation of our registration statement on Form S-1 for our initial public offering and compliance with public reporting requirements, some of which are believed to be non-recurring. Personnel costs were higher due to an increase in employees throughout the organization.

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 our current credit facility which resulted in higher average borrowings outstanding.

Year Ended December 31, 2010 Compared to Six Months Ended December 31, 2009

Sales Revenues. Revenues from oil and natural gas sales for the year ended December 31, 2010 were approximately $18.3 million as compared to $6.5 million for the six months ended December 31, 2009. The increase in revenues was primarily due to an increase in oil production and an increase in the average oil and natural gas price during the twelve months ended December 31, 2010.

Our production volumes for the twelve months ended December 31, 2010 were 260 MBoe, or 710 Boe per day. In comparison, our production volumes for the six months ended December 31, 2009 were 110 MBoe, or 602 Boe per day. The increase In addition, in production volumes was primarily due to the drilling programs in our waterflood units and the acquisitions of interests in various properties located in Oklahoma. Our average sales price per barrel for oil, excluding commodity derivative contracts, for the year ended December 31, 2010 was $73.92, compared with $65.85 for the six months ended December 31, 2009.

Effects of Commodity Derivative Contracts. Due to changes in commodity prices, we recorded a net loss from our commodity hedging program for the year ended December 31, 2010 of approximately $0.8 million, which is composed of a realized loss of $0.1 million and an unrealized loss of $0.7 million. For the six months ended December 31, 2009, we recorded a net loss from the commodity hedging program of approximately $0.5 million, which is composed of a realized loss of $0.4 million and an unrealized loss of $0.1 million.

Lease Operating Expenses. Our lease operating expenses were $6.2 million for the year ended December 31, 2010, or $23.99 per Boe, compared to $2.4 million for the six months ended December 31, 2009, or $22.10 per Boe. The increase in lease operating expenses, on both a total and per Boe basis, was primarily due to the increase in production and the increase in the number of wells drilled and used for injection during the twelve months ended December 31, 2010. Ad valorem taxes are also reflected in lease operating expenses.

Production Taxes. Our production taxes were $0.8 million for the year ended December 31, 2010, or $3.16 per Boe for an effective tax rate of 4.5%, compared to $0.3 million for the six months ended

December 31, 2009, or $2.45 per Boe for an effective tax rate of 4.2%. The increase in production taxes during the year ended December 31, 2010 was primarily due to the increase in the realized average oil sales price. The increase in the effective tax rate was due to increased production from certain of our Oklahoma properties that do not qualify for reduced tax rates.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses for the year ended December 31, 2010 were $5.2 million, or $20.02 per Boe produced, compared to $2.4 million, or $21.43 per Boe produced, for the six months ended December 31, 2009. The decrease per Boe produced was primarily due to an increase in proved developed reserves during the year ended December 31, 2010.

Impairment of Oil and Natural Gas Properties. An impairment of $1.9 million was required during the year ended December 31, 2010 due to a decline in reserve estimates for certain producing properties. An impairment expense of $9.2 million was also recorded for the six months ended December 31, 2009 due to a decline in reserve estimates for certain producing properties.

General and Administrative Expenses. Our general and administrative expenses were approximately $1.0 million for the year ended December 31, 2010, or $3.78 per Boe produced, compared to $0.7 million of general and administrative expenses for the six months ended December 31, 2009, or $6.40 per Boe produced. The decrease in general and administrative expenses per Boe in the year ended December 31, 2010 was primarily due to increased affiliate subsidiary activity resulting in the subsidiaries receiving a greater allocation of the overall general and administrative expenses.

Interest Expense. Our interest expense for the year ended December 31, 2010 was $98,000 compared to $2,000 for the six months ended December 31, 2009. The increase is attributable to an increase in 2011, we entered into our current credit facility which resulted in higher average borrowings from our credit facilities due to capital expenditures and acquisitions.

Six Months Ended December 31, 2009 Compared to Year Ended June 30, 2009

Sales Revenues. Revenues from oil and natural gas sales for the six months ended December 31, 2009 were approximately $6.5 million as compared to $12.4 million for the twelve months ended June 30, 2009.

Our production volumes for the six months ended December 31, 2009 were 110 MBoe, or 602 Boe per day. In comparison, our production volumes for the year ended June 30, 2009 were 210 MBoe, or 575 Boe per day. The increase in production in Boe per day was due to an increase in oil production partially offset by a decline in natural gas production. Our average sales price per barrel for oil, excluding commodity derivative contracts, for the six months ended December 31, 2009 was $65.85 compared with $66.87 for the year ended June 30, 2009.

Effects of Commodity Derivative Contracts. Due to changes in commodity prices, we recorded a net loss from the commodity hedging program for the six months ended December 31, 2009 of approximately $0.5 million, which was composed of a realized loss of $0.4 million and an unrealized loss of $0.1 million. For the year ended June 30, 2009, we recorded realized net gain from the commodity hedging program of approximately $1.0 million, which was composed of $0.7 million of realized loss and an unrealized gain of $1.7 million.

Lease Operating Expenses. Our lease operating expenses were $2.4 million, or $22.10 per Boe produced for the six months ended December 31, 2009 compared to approximately $5.4 million, or $25.56 per Boe produced for the year ended June 30, 2009. The decrease in lease operating expenses per Boe was attributable to an increase in production.

Production Taxes. Our production taxes were $0.3 million for the six months ended December 31, 2009, or $2.45 per Boe for an effective tax rate of 4.2%, compared to $0.6 million for the year ended June 30, 2009, or $3.00 per Boe for an effective tax rate of 5.1%. The decrease in production taxes on a per unit basis during the year ended December 31, 2009 was primarily due to a decrease in the effective tax rate. The decrease in the effective tax rate was due to increased production from certain of our Oklahoma properties that qualify for reduced tax rates.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses for the six months ended December 31, 2009 were $2.4 million, or $21.43 per Boe produced, as compared to $2.1 million, or $10.01 per Boe produced, for the year ended, June 30, 2009. The increase per Boe produced for the six months ended December 31, 2009 was primarily due to a decrease in reserve estimates on a total basis for some of our non-performing properties.

Impairment of Oil and Natural Gas Properties. An impairment of $9.2 million was required during the six months ended December 31, 2009 due to a decline in reserve estimates for certain producing properties. There were no impairment charges for the year ended June 30, 2009.

General and Administrative Expenses. Our general and administrative expenses were approximately $0.7 million for the six months ended December 31, 2009, or $6.40 per Boe produced, compared to $1.8 million of general and administrative expenses for the year ended June 30, 2009 or $8.41 per Boe produced. The decrease in general and administrative expenses per Boe produced was primarily due to an increase in production.

Interest Expense. Our interest expense for the six months ended December 31, 2009 was $2,000 compared to $93,000 for the year ended June 30, 2009. The decrease is attributable to reduced debt resulting from a capital contribution during the six months ended December 31, 2009.

Liquidity and Capital Resources

Prior to our initial public offering, our primary sources of liquidity and capital resources were proceeds from capital contributions from Yorktown, bank borrowings, and cash flow from operations. Our primary uses of capital were for the acquisition, development and drilling of waterflood units.

As a publicly traded partnership, our primary sources of liquidity and capital resources are from cash flow generated by operating activities and borrowings under our credit facility. We also expect to be able to issue additional equity and debt securities from time to time as market conditions allow. 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 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, weather and other factors.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to our unitholders and our general partner. In making cash distributions, our general partner will attempt to avoid large variations in the amount we distribute from quarter to quarter. In order to facilitate this, our partnership agreement permits our general partner to establish cash reserves to be used to pay distributions for any one or more of the next four quarters.

In addition, our partnership agreement permits us to borrow funds to make distributions to our unitholders. We may borrow to make distributions to our unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long-term, but short-term factors have caused available cash from operations to be insufficient to sustain our level of distributions. For example, we

Table of Contents

generally intend to hedge a significant portion of our production. We generally will be required to settle our commodity hedge derivatives within five days of the end of the month. As is typical in the oil and gas industry, we do not generally receive the proceeds from the sale of our hedged production until 20 to 60 days following the end of the month. As a result, when commodity prices increase above the fixed price in the derivative contracts, we will be required to pay the derivative counterparty the difference between the fixed price in the derivative contract and the market price before we receive the proceeds from the sale of the hedged production. If this occurs, we may borrow to fund our distributions.

Cash Flow

Net cash provided by operating activities was approximately $24.1 million, $11.8 million, $10.9 million, $24.4 million, $5.2 million and $1.0 million for the twelve months ended December 31, 2011, December 31, 2010 and June 30, 2009 and for the six months ended June 30, 2012, June 30, 2011, and December 31, 2009, respectively. Our revenues increased significantly for the year ended December 31, 2011 and for the six months ended June 30, 2012 compared to prior periods, 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 and, therefore, our net cash provided by operating activities increased during the same period. Cash provided by operating activities is impacted by the prices received for oil and natural gas and levels of 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.

Net cash used in investing activities was approximately $42.0 million, $22.7 million, $12.4 million, $24.0 million, $13.4 million and $5.0 million for the twelve months ended December 31, 2011, December 31, 2010 and June 30, 2009 and for the six months ended June 30, 2012, June 30, 2011 and December 31, 2009, respectively. The increased amount of cash used in investing activities was primarily due to the increased waterflood development activities in Southern Oklahoma, including the in-field drilling in these units, development activity in our Northeastern Oklahoma core area and acquisitions.

Net cash (used in) provided by financing activities was approximately $17.9 million, $10.4 million, $4.8 million, $3.3 million, $8.4 million and ($1.2) million for the twelve months ended December 31, 2011, December 31, 2010 and June 30, 2009 and for the six months ended June 30, 2012, June 30, 2011 and December 31, 2009, respectively. During the six months ended June 30, 2012, we used net borrowings of $13.0 million from our credit facility to finance the purchase of certain oil properties located in our Northeastern Oklahoma core area and certain working interests in our existing units in our Southern Oklahoma core area and paid cash distributions of approximately $9.7 million. For the six months ended June 30, 2011, net cash provided by financing activities was used to acquire the War Party I and II Units in our Hugoton Basin core area. For the six months ended December 31, 2009, net cash provided by financing activities was used to fund a $1.5 million distribution to our members. For the year ended December 31, 2011, we received net proceeds of $87.4 million from our initial public offering, 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 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. For the twelve months ended June 30, 2009, the cash provided by financing activities primarily related to $5.0 million of capital contributions.

Table of Contents

Working Capital

Our working capital totaled $11.9 million, $2.4 million, $4.4 million, ($1.2) million and $2.4 million at June 30, 2012, December 31, 2011, June 30, 2011, December 31, 2010 and December 31, 2009, respectively. Our cash balances at June 30, 2012, December 31, 2011, June 30, 2011, December 31, 2010 and December 31, 2009 were $4.0 million, $0.2 million, $0.4 million, $0.2 million and $0.8 million, respectively. The negative working capital at December 31, 2010 was directly related to accrued expenses for our drilling program and the accrued unrealized loss on our commodity derivative contracts. In addition, the working capital amount at December 31, 2010 excluded $5.3 million of maturities under our prior credit facilities. These facilities were repaid in full with proceeds from our initial public offering.

Capital Expenditures

We have budgeted a total of $15.6 million capital expenditures for 2012 based on our December 31, 2011 audited reserves and have spent $7.6 million during the six months ending June 30, 2012, which includes $2.4 million for maintenance capital expenditures. Maintenance capital expenditures are capital expenditures that we expect to make on an ongoing basis to maintain our waterflood operations and production over the long-term. Our maintenance capital expenditures are intended to maintain the appropriate injection, reservoir pressure and resulting production response. While our maintenance capital expenditures are focused on maintaining our existing production, they could also create production increases as well. We estimate that maintenance capital expenditures will average approximately $5.0 million per year through the next five years.

Growth capital expenditures are capital expenditures that we expect to make to either develop new waterfloods or add primary production through newly initiated development programs. The primary purpose of growth capital expenditures is to acquire, develop and produce assets that will allow us to increase our production levels and asset base in a manner that is expected to be accretive to our unitholders and, as a result, increase our distributions per unit. Growth capital expenditures on existing properties may include projects such as drilling new injection wells or producing wells on our existing waterflood projects which are at an early stage of development. Growth capital expenditures may also include acquisitions of additional oil and gas properties, including new producing wells that are either in the primary stage of production or in the secondary stage of production but which we believe have upside potential. Although we intend to make acquisitions in the future, including potential acquisitions of producing properties from the Mid-Con Affiliates, we currently have no budgeted growth capital expenditures related to acquisitions, as we cannot be certain that we will be able to identify attractive properties or, if identified, that we will be able to negotiate acceptable purchase contracts.

We generally plan to use cash flow from operations to fund our maintenance capital expenditures. We plan primarily to use external financing sources, including borrowings under our credit facility and the issuance of debt and equity securities, to make growth capital expenditures. Because our proved reserves and production are expected to decline over time, we will need to continue the development of our existing reserves and/or make acquisitions to maintain and grow our distributions to unitholders over time.

If cash flow from operations does not meet our expectations, we may reduce our level of capital expenditures, reduce distributions to our unitholders, and/or fund a portion of our capital expenditures using borrowings under our credit facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot be certain that budgeted capital will be available on acceptable terms or at all. The covenants in our credit facility could limit our ability to incur additional indebtedness. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to make growth capital expenditures or even fund the capital expenditures necessary to maintain our production or proved reserves.

Table of Contents

The amount and timing of our capital expenditures are largely discretionary and within our control. If oil and natural gas prices decline below levels we deem acceptable, we may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside of our control that could affect the timing of our expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and labor crews. Based on our current oil and natural gas price expectations, we anticipate that our cash flow from operations and available borrowing capacity under our credit facility will exceed our planned capital expenditures and other cash requirements for the twelve months ending December 31, 2012. However, future cash flow is subject to a number of variables, including the level of our oil and natural gas production and the prices we receive for our oil and natural gas production. We cannot be certain that our operations and other capital resources will provide cash in amounts that are sufficient to maintain our planned levels of capital expenditures.

Credit Facility

Our wholly owned subsidiary, Mid-Con Energy Properties, as borrower, and we, as guarantor, have a $250.0 million senior secured 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 partners. The facility requires the maintenance of a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (each as defined in the credit agreement) of not more than 4.0 to 1.0, and a current ratio of not less than 1.0 to 1.0. As of June 30, 2012, we were in compliance with all of the facility s financial covenants.

Borrowings under the facility may not exceed our current borrowing base of $100.0 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 optional redetermination during the period between each scheduled borrowing base determination, either at our request or at the request of the lenders. An optional 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.

Additionally, borrowings under the facility will bear interest, at Mid-Con Energy Properties option, at either (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 Inter-Bank Offered Rate (LIBOR) plus 1.0% , all of which is 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. 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. At June 30, 2012, we had $58.0 million of borrowings outstanding under our credit facility.

We continue to 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 June 30, 2012, our $250.0 million senior secured credit facility had borrowing capacity of $42.0 million ($100.0 million borrowing base less $58.0 million of outstanding borrowings under our credit facility). On April 23, 2012, the borrowing base of our credit facility increased from $75.0 million to $100.0 million, and on September 20, 2012 the borrowing base was reaffirmed by our lenders at $100.0 million.

Table of Contents

Derivative Contracts

For the three months ending December 31, 2012 and years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of our fourth quarter 2012 and calendar years 2013 and 2014 average daily oil production (as estimated from the projection of our oil production in our audit of proved reserves as of December 31, 2011).

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.

Term	Type of Derivative	Weighted Average ($/Bbl)	Bbls/d
2012	Swaps	$ 101.85	1,207
2012	Put/Call (Collars)	$ 100 $117	196
2013	Swaps	$ 100.14	1,216
2013	Put/Call (Collars)	$ 97.67 108.08	296
2014	Swaps	$ 94.30	1,315

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. For the three months ending December 31, 2012 and the years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of our fourth quarter 2012 and calendar years 2013 and 2014 average daily oil production (as estimated from the projection of our oil production in our reserve audit of proved reserves as of December 31, 2011). All of our derivative contracts for 2012, 2013 and 2014 are either swaps with fixed settlements or collars. The weighted average minimum prices on all of our derivative contracts for 2012, 2013 and 2014 are $101.59, $99.66 and $94.30, respectively.

The following table details, for the periods indicated, our oil swaps and collars, through December 31, 2014. These transactions are settled based upon the NYMEX-WTI price of oil.

Months Outstanding	Settlement Price	Floor	Ceiling	Instrument Type	Total Bbls. Per Month	NYMEX Index
Oct-Dec 2012		$ 100.00	$ 117.00	Collar	6,000	WTI
Oct-Dec 2012	$ 104.28			Swap	6,000	WTI
Oct-Dec 2012	$ 100.00			Swap	8,000	WTI
Oct-Dec 2012	$ 100.97			Swap	10,000	WTI
Oct-Dec 2012	$ 99.95			Swap	5,000	WTI
Oct-Dec 2012	$ 101.40			Swap	5,000	WTI
Oct-Dec 2012	$ 108.80			Swap	3,000	WTI

Table of Contents

Months Outstanding	Settlement Price	Floor	Ceiling	Instrument Type	Total Bbls. Per Month	NYMEX Index
Jan-Dec 2013		$ 100.00	$ 111.00	Collar	6,000	WTI
Jan-Dec 2013	$ 105.80			Swap	6,000	WTI
Jan-Dec 2013	$ 96.00			Swap	8,000	WTI
Jan-Dec 2013	$ 97.70			Swap	5,000	WTI
Jan-Dec 2013	$ 99.05			Swap	5,000	WTI
Jan-Dec 2013	$ 100.05			Swap	5,000	WTI
Jan-Dec 2013	$ 104.70			Swap	5,000	WTI
Jan-Dec 2013	$ 98.30			Swap	3,000	WTI
Jan-Dec 2013		$ 93.00	$ 102.25	Collar	3,000	WTI
Jan-Dec 2014	$ 96.10			Swap	5,000	WTI
Jan-Dec 2014	$ 100.00			Swap	5,000	WTI
Jan-Dec 2014	$ 97.40			Swap	5,000	WTI
Jan-Dec 2014	$ 97.96			Swap	5,000	WTI
Jan-Dec 2014	$ 89.50			Swap	5,000	WTI
Jan-Dec 2014	$ 89.35			Swap	5,000	WTI
Jan-Dec 2014	$ 89.87			Swap	5,000	WTI
Jan-Dec 2014	$ 94.25			Swap	5,000	WTI

Contractual Obligations

A summary of our contractual obligations as of June 30, 2012 is provided in the following table.

	Obligations Due in Period					
Contractual Obligation	2012	2013	2014	2015	Thereafter	Total
			(in thousands)			
Long-term debt	$	$	$	$	$ 58,000	$ 58,000
Interest on long-term debt(1)	725	1,450	1,450	1,450	1,406	6,481
Total contractual obligations	$ 725	$ 1,450	$ 1,450	$ 1,450	$ 59,406	$ 64,481

(1) Based upon an average interest rate of approximately 2.5% under the credit facility at June 30, 2012.

Quantitative and Qualitative Disclosure about Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. 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.

Table of Contents

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.

Swaps

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.

For a summary of the oil swaps and swap prices, related basis swap prices and resulting adjusted swap prices in place as of June 30, 2012, please read Liquidity and Capital Resources Derivative Contracts.

Put/Call Options

A combination of a put option we purchase and a call option we sell is often referred to as a put/call or a collar. 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.

For a summary of the oil collars in place as of June 30, 2012, please read Liquidity and Capital Resources Derivative Contracts.

Interest Rate Risk

At June 30, 2012, we had $58.0 million of debt outstanding under our credit facility, with an effective interest rate of approximately 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 $145,000 on an annual basis. Our credit facility allows us to borrow up to $100.0 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 is the United States prime rate as announced from time-to-time by the Royal Bank of Canada.

Counterparty and Customer Credit Risk

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. 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.

We are also subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our 2012 production. The inability or failure of any of our customers to meet its obligations to

Table of Contents

us or its insolvency or liquidation may adversely affect our financial results. However, Sunoco Logistics, Enterprise, Coffeyville Resources and Vitol each have positive payment histories, and Sunoco Logistics and Enterprise each have investment grade credit ratings and Coffeyville Resources is rated one level below investment grade. Accordingly, we believe that the credit quality of such customers is high.

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 demonstrated, 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, 2011 included in this prospectus are based on a reserve report 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 natural gas liquids eventually recovered.

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.

Table of Contents

Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as costs related to proved properties. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. We will assess unproved properties for impairment quarterly on the basis of our experience in similar situations and other factors such as the primary lease terms of the properties, the average holding period of unproved 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 unproved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors.

Impairment of Oil and Natural Gas Properties

For the year ended December 31, 2010 we recorded a non-cash impairment charge of approximately $1.9 million, primarily associated with proved oil and natural gas properties related to unfavorable market conditions. For the year ended December 31, 2010, approximately $0.6 million of the impairment charge was associated with properties that were sold to the Mid-Con Affiliates. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair-value measurement. The charges are included in impairment of oil and natural gas properties in our combined statement of operations. We recorded no impairment charge for proved oil and natural gas properties for the year ended December 31, 2011 or for the six months ended June 30, 2012.

Asset Retirement Obligations

The initial estimated asset retirement obligation 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 asset retirement obligation 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 asset retirement obligations.

Revenue Recognition

Oil and natural gas revenues are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable.

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 exchange-traded transactions. Valuation is determined by reference to readily available public data.

Table of Contents

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 hedging instruments during the year ended December 31, 2011, the six months ended June 30, 2011, or the six months ended June 30, 2012, respectively.

Recently Issued Accounting Pronouncements

No new accounting pronouncements issued or effective during the six months ended June 30, 2012 have had or are expected to have a material impact on our consolidated financial statements.

Internal Controls and Procedures

Because we are a publicly traded partnership, we are required to comply with the SEC s rules implementing Sections 302 and 404 of the Sarbanes-Oxley Act of 2002, which require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal controls over financial reporting. Though we will be required to disclose changes made to our internal controls and procedures on a quarterly basis, we are not required to make our first annual assessment of our internal controls over financial reporting pursuant to Section 404 until 2013.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2009, 2010 and 2011. Although the impact of inflation has been insignificant in recent years, it is still a factor in the U.S. economy, and we tend to experience inflationary pressure on the cost of oilfield services and equipment, as increasing oil prices increase drilling activity in our areas of operations.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Table of Contents

BUSINESS AND PROPERTIES

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 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. 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, 2011, our total estimated proved reserves were 10.0 MMBoe, of which approximately 99% were oil and approximately 69% were proved developed, both on a Boe basis. As of December 31, 2011, Mid-Con Energy Operating operated 99% of our properties and 96% were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended June 30, 2012 was approximately 1,844 Boe per day and based on our December 31, 2011 audited reserves, as adjusted for average net production for the six months ended June 30, 2012, our estimated proved reserves had a reserve-to-production ratio of approximately 15 years. As of December 31, 2011, our management team developed approximately 59% of our total reserves through new waterflood projects.

Our properties are located in the Mid-Continent region of the United States and primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates. Our core areas of operation are located in Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. As of December 31, 2011, approximately 91% of the properties associated with our estimated reserves, on a Boe basis, have been producing continuously since 1982 or earlier. Through the application of waterflooding, we believe these mature properties have attractive upside potential. Waterflooding, a form of secondary oil recovery, works by repressuring a reservoir through water injection and pushing or sweeping oil to producing wellbores. Based on the production estimates from our December 31, 2011 audited reserves, the average estimated decline rate for our proved developed producing reserves is approximately 8.0% for 2012 and, on a compounded average decline basis, approximately 11% for the subsequent five years and approximately 10% thereafter.

The following table summarizes information by core area regarding our estimated oil and natural gas reserves as of December 31, 2011 and our average net production for the month ended June 30, 2012.

	Estimated Net Proved Reserves as of December 31, 2011				Average Net Production for the Month Ended June 30, 2012			Gross Active Wells as of June 30, 2012		
	(MBoe)	% Operated(1)	% Oil	% Proved Developed	Boe/d Gross	Boe/d Net	Reserve-to-Production Ratio(2)	Oil and Natural Gas Wells	Injection Wells	Shut-in/ Waiting on Completion
Southern Oklahoma	5,528	100%	100%	68%	2,600	1,128	13	79	53	12
Northeastern Oklahoma	3,179	100%	99%	69%	742	447	19	201	76	54
Hugoton Basin	1,060	100%	99%	69%	340	219	13	29	15	13
Other	282	77%	77%	100%	140	50	15	11	5	2
Total	**10,049**	**99%**	**99%**	**69%**	**3,822**	**1,844**	**15**	**320**	**149**	**81**

Table of Contents

(2) The reserve-to-production ratio is calculated by subtracting production for the six months ended June 30, 2012 from estimated net proved reserves as of December 31, 2011 and dividing the result by average net production for the month ended June 30, 2012.

The following chart summarizes our total average net Boe production volumes on a monthly basis, and illustrates the 47% increase in our production volumes over the twelve months ended June 30, 2012. We achieved this production increase primarily through ongoing waterflood response from existing development activities and from workovers and acquisitions.

Recent Developments

On October 15, 2012, we entered into a Purchase and Sale Agreement to acquire certain oil properties located in our Hugoton Basin core area. The base purchase price for such properties, which is subject to standard adjustments and preference right exercises, is approximately $21 million, which includes a performance deposit of $2.1 million. This acquisition is expected to close on or before November 6, 2012 and will be financed using existing cash and borrowings from our credit facility. This acquisition includes current net production of approximately 175 Boe per day, estimated net proved reserves of approximately 1.3 MMBoe (55% proved developed producing and 99% oil on a Boe basis) and a reserve-to-production ratio of approximately 20 years. We will acquire 14 gross producing, 7 gross injecting and 1 gross water supply well associated with these properties. The estimated proved reserves for this acquisition were based on our preliminary internal evaluation of information provided by the seller and proved reserves as of the acquisition date for the above-referenced acquisition were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that this acquisition will be immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for this property may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Additionally, on October 12, 2012, we entered into an agreement to assign additional working interests in our existing War Party I and II Units located in our Hugoton Basin core area, effective as of April 1, 2012. Pursuant to this agreement, we will pay approximately $3.5 million for these properties using existing cash and borrowings from our credit facility. As a result of this assignment, we will have 100% and 99% of the working interests in our War Party I and II Units, respectively. The working interests to be assigned include current net production of approximately 83 Boe per day, estimated net proved reserves of approximately 0.5 MMBoe (85% proved developed producing and 99% oil on a Boe basis) and a reserve-to-production ratio of approximately 20 years. The estimated proved reserves for the working interests to be assigned are based on our preliminary internal evaluation of information provided by the seller, and proved reserves as of the effective date for the above-referenced assignment is estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that the working interests included in this assignment will be immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for this property may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Completion of these acquisitions are subject to the satisfaction of customary closing conditions and the waiver of preference rights and obtaining necessary consents from third parties. Failure to satisfy these conditions, if not waived, would prevent us from consummating these acquisitions or the amount of properties we may obtain may be materially reduced, resulting in a proportional decrease in our expected net reserves and production. As a result, we can provide no assurance that these acquisitions will be completed within the anticipated time frame, or at all. The closing of these acquisitions is not conditioned on the closing of this offering, and this offering is not conditioned on the closing of these acquisitions. In the event that we are unable to complete these acquisitions, our approximately $2.1 million deposit we have paid for the Clawson Ranch would potentially be subject to forfeiture.

During June 2012, we acquired certain oil properties located in our Northeastern Oklahoma core area, and additional working interests in our existing units in our Southern Oklahoma core area, in unrelated transactions. We paid approximately $16.4 million in aggregate consideration for these properties. The transactions were financed using existing cash and borrowings from our credit facility. These acquisitions include current net production of approximately 115 Boe per day, estimated net proved reserves of approximately 0.6 MMBoe (53% proved developed producing and 100% oil on a Boe basis) and an average reserve-to-production ratio of approximately 14 years. The estimated proved reserves for these acquisitions were based on our preliminary internal evaluation of information provided by the sellers and proved reserves as of the acquisition date for the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. We believe that these acquisitions were immediately accretive to distributable cash flow on a per unit basis pro forma for this offering. Actual reserves and production for these properties may be different in the future. Please read Risk Factors Risks Related to Our Business Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

Table of Contents

Our general partner also declared a cash distribution of $0.485 per unit ($1.94 per unit on an annualized basis) on October 15, 2012 for the third quarter of 2012, which will be paid on November 14, 2012 to unitholders of record at the close of business on November 7, 2012. This is an increase of $0.01 from the previous quarter. Our management also confirmed on October 15, 2012 that our previously released Boe production guidance for the third quarter of 2012 will come in within the previously announced range, likely toward the lower-end.

Our Hedging Strategy

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. For the three months ending December 31, 2012 and the years ending December 31, 2013 and 2014, we have commodity derivative contracts covering approximately 69.9%, 69.6% and 57.0%, respectively, of our fourth quarter 2012 and calendar years 2013 and 2014 average daily oil production (as estimated from the projection of our oil production in our audit of proved reserves as of December 31, 2011). All of our derivative contracts for 2012, 2013 and 2014 are either swaps with fixed settlements or collars. The weighted average minimum prices on all of our derivative contracts for 2012, 2013 and 2014 are $101.59, $99.66 and $94.30, respectively.

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 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Derivative Contracts.

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 above, 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, 2011. 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.

Table of Contents

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, 2011, 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 will 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 will afford us the financial flexibility to execute our business strategies. We believe our borrowing capacity under our credit facility, our access to capital markets and internally generated cash flow will provide 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 interests 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.

Table of Contents

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 96% 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, 2011 audited reserves, the average estimated decline rate for our existing proved developed producing reserves is approximately 8% for 2012 and, on a compounded average decline basis, approximately 11% 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 been spent prior to this offering. 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 seven years, we identified, initiated, acquired, formed and developed over 27% of all new waterflood projects in the State of Oklahoma, while the next most active competitor formed only 6% 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 plan to 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. Prior to this offering, Yorktown owned an approximate 48.5% limited partner interest in us, making it our largest unitholder. Following this offering, Yorktown will own an approximate 30.1% limited partner interest in us (or an approximate 26.9% limited partner interest in us if the underwriters exercise in full their option to purchase additional common units) and will continue to be our largest unitholder. Yorktown Energy Partners IX, L.P. will continue to own 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, we believe that 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, 2011, 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. We believe that 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 future acquisitions of oil and, when advantageous, natural gas properties. We also believe our low level of indebtedness and our ability to issue additional common units and other partnership interests in connection with these acquisitions will improve our financial flexibility. Further, we have an available borrowing capacity of approximately $42.0 million under our credit facility after giving effect to approximately $58.0 million previously borrowed thereunder, which provides us with another potential means of financing acquisition opportunities.

The range and depth of our technical and operational expertise will allow us to expand both geographically and operationally to achieve our goals. During the past nine years, 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 more than 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, we believe that 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. We believe that our wealth of experience may enable 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.

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 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 plan to avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire. However, 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. For a summary of the process by which such mutually agreeable prices will be determined, please read Certain Relationships and Related Party Transactions Review, Approval or Ratification of Transactions with Related Persons.

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. Yorktown made several equity investments in our predecessor. Prior to this offering, Yorktown owned an approximate 48.5% limited partner interest in us, making it our largest unitholder. Following this offering, Yorktown will own an approximate 30.1% limited partner interest in us (or an approximate 26.9% limited partner interest in us if the underwriters exercise their option to purchase additional common units), and will continue to be our largest unitholder. Yorktown Energy Partners IX, L.P. will continue to own 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, we believe that 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, including the Mid-Con Affiliates, that compete with us.

Oil Recovery Overview

When an oil field is first produced, the oil typically is recovered as a result of expansion of reservoir fluids which are naturally pressured within the producing formation. The only natural force present to move the oil through the reservoir rock to the wellbore is the pressure differential between the higher pressure in the rock formation and the lower pressure in the producing wellbore. Various types of pumps are often used to reduce pressure in the wellbore, thereby increasing the pressure differential. At the same time, there are many factors that act to impede the flow of oil, depending on the nature of the formation and fluid properties, such as pressure, permeability, viscosity and water saturation. This stage of production, referred to as primary recovery, recovers only a small fraction of the oil originally in place in a producing formation, typically ranging from 10% to 25%.

After the primary recovery phase many, but not all, oil fields respond positively to secondary recovery techniques in which external fluids are injected into a reservoir to increase reservoir pressure and to displace oil towards the wellbore. Secondary recovery techniques often result in increases in production and reserves above primary recovery. Waterflooding, a form of secondary recovery, works by repressuring a reservoir through water injection and sweeping or pushing oil to producing wellbores. Conventional hydraulic fracturing techniques are often employed to increase a well s productivity in waterflooding.

Table of Contents

Through waterflooding, water injection replaces the loss of reservoir pressure caused by the primary production of oil and gas, which is often referred to as pressure depletion or reservoir voidage. As a result of the water used in a waterflood, produced fluids contain both water and oil, with the relative amount of water increasing over time. Surface equipment is used to separate the oil from the water, with the oil going to pipelines or holding tanks for sale and the water being recycled to the injection facilities. In general, in the Mid-Continent region, a secondary recovery project may produce an additional 10% to 20% of the oil originally in place in a reservoir.

A third stage of oil recovery is called tertiary recovery. In addition to maintaining reservoir pressure, this type of recovery seeks to alter the properties of the oil in ways that facilitate additional production. The three major types of tertiary recovery are chemical flooding, thermal recovery (such as a steamflood) and miscible displacement involving carbon dioxide (CO_2), hydrocarbon or nitrogen injection. We are currently field testing new technologies in chemical flooding on some of our properties. If successful, this testing may lead to reserve and production increases in the future. Any future tertiary development programs and subsequent capital expenditures would be contingent upon commercial viability established by successful pilot testing. At this time, there are no estimated reserves or production associated with tertiary recovery projects assigned to our properties. We will continue to review future opportunities for growth through the use of various tertiary recovery techniques.

Our 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. These core areas are each composed of multiple 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 allow 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 read Summary of Oil Properties and Projects.

Our properties consist of mature, legacy onshore oil reservoirs, approximately 96% of the reserves of which are being produced under waterflood 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 offsets declines from mature waterflood areas, leading to more stable cash flow and production.

We use words such as mature or legacy to describe our properties as having established operating, reservoir and production characteristics. The production and corresponding decline rates attributable to properties of this type in contrast with more recently drilled properties can generally be forecast with a greater degree of accuracy. Our ability to predict future performance is further enhanced by the familiarity that we have with most of our properties. We have observed the performance of many of our properties over many years, in many cases from the inception of waterflooding. This long-term observation allows for greater understanding of production and reservoir characteristics, making future performance more predictable.

As of June 30, 2012, we owned a 68% average working interest across 320 gross producing (224 net) wells, 149 gross injection (97 net) wells, and 81 gross (67 net) wells shut-in or waiting on completion. Mid-Con Energy Operating operates 99% of our properties by value, as calculated using the standardized measure. Approximately 97% of our revenue is derived from the proceeds of oil production. Based on the standardized measure, our value-weighted average working interest on these properties was approximately 68% based on our December 31, 2011 audited reserves. Our estimated proved reserves as of December 31, 2011 were 10.0 MMBoe, of which approximately 99% were oil and approximately 69% were

Table of Contents

proved developed, both on a Boe basis. Based on production estimates from our December 31, 2011 audited reserves, the average estimated decline rate for our existing proved developed producing reserves is approximately 8.0% for 2012, approximately 11% for the subsequent five years and, on a compounded average decline basis, approximately 10% thereafter.

The following table shows 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, 2011, 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 June 30 2012		Estimated Net Proved Reserves as of December 31, 2011(3)						
	Net (Boe/d)	% of Total	MBoe	% of Total Proved Reserves	% Oil	% Proved Developed Reserves	Undiscounted Cap. Ex. (in millions)	Standardized Measure(2)(3) (in millions)	% of Total
Southern Oklahoma Fields/Units:									
Highlands(1)	412	22%	2,621	26%	100%	78%	$ 9	$ 110	34%
Battle Springs(1)	330	18%	1,144	11%	100%	79%	$ 4	$ 50	15%
Twin Forks (1)	308	17%	851	9%	100%	72%	$ 3	$ 34	10%
Ardmore West(1)	26	1%	750	8%	100%	2%	$ 3	$ 25	8%
Southeast Hewitt	37	2%	137	1%	100%	100%	$ 0	$ 5	2%
Other Fields/Units	15	<1%	25	0%	78%	100%	$ 0	$ 1	0%
Total Southern Oklahoma	**1,128**	**60%**	**5,528**	**55%**	**100%**	**68%**	**$ 19**	**$ 225**	**69%**
Northeastern Oklahoma Fields / Units:									
Cleveland	299	16%	1,959	20%	99%	66%	$ 3	$ 45	14%
Cushing	101	5%	765	8%	98%	82%	$ 2	$ 17	5%
Skiatook(1)	36	2%	426	4%	100%	58%	$ 1	$ 8	2%
Other Fields/Units	11	1%	29	0%	98%	100%	$ 0	$ 1	0%
Total Northeastern Oklahoma	**447**	**24%**	**3,179**	**32%**	**99%**	**69%**	**$ 6**	**$ 71**	**21%**
Hugoton Fields / Units:									
War Party I(1)	70	4%	232	2%	100%	84%	$ 2	$ 3	1%
War Party II(1)	90	5%	510	5%	99%	75%	$ 1	$ 10	3%
Harker Ranch(1)	59	3%	318	3%	100%	47%	$ 3	$ 10	3%
Total Hugoton	**219**	**12%**	**1,060**	**10%**	**99%**	**69%**	**$ 6**	**$ 23**	**7%**
Other Fields / Units:									
Decker(1)	19	1%	216	2%	100%	100%	$ 0	$ 7	2%
Miscellaneous	31	3%	66	1%	0%	100%	$ 0	$ 2	1%
Total Other	**50**	**4%**	**282**	**3%**	**77%**	**100%**	**$ 0**	**$ 9**	**3%**
All Fields	**1,844**	**100%**	**10,049**	**100%**	**99%**	**69%**	**$ 31**	**$ 328**	**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 Standards Board Accounting Standards Codification Topic 932, *Extractive Activities 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 $96.19 per Bbl for oil and $4.11 per MMBtu for natural gas for the 12 months ended December 31, 2011.

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, 2011, 96% of our average daily net production for the month ended June 30, 2012 and 99% of our standardized measure as of December 31, 2011. Please read Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations in evaluating the material presented below. 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, 2011 audited reserves and production and well status for the month ending June 30, 2012.

Southern Oklahoma

Highlands Unit. The Highlands Unit is in the SE Joiner City Field, an oil-weighted field located in Love County, Oklahoma. Since its discovery in 1980, the Highlands Unit has produced approximately 3,247 MBoe. 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 27 gross (19 net) producing, 23 gross (17 net) injection and 2 gross (1 net) recently drilled but not completed wells in this unit with an average working interest of 72%. As of June 30, 2012, our properties in this unit were producing 878 Boe per day gross, 412 Boe per day net. As of December 31, 2011, the Highlands Unit contained 2,621 MBoe of estimated net proved reserves.

Battle Springs Unit. The Battle Springs Unit is in the SE Joiner City Field, an oil-weighted field located in Love County, Oklahoma. Since its discovery in 1982, the Battle Springs Unit has produced approximately 2,928 MBoe. 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 and 15 gross injection (8 net) wells in this unit with an average working interest of 51%. As of June 30, 2012, our properties in this unit were producing 818 Boe per day gross, 330 Boe per day net. As of December 31, 2011, the Battle Springs Unit contained 1,144 MBoe of estimated net proved reserves.

Twin Forks Unit. The Twin Forks Unit is in the SE Joiner City Field, an oil-weighted field located in Carter County, Oklahoma. Since its discovery in 1979, the Twin Forks Unit has produced approximately 1,223 MBoe. 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 7 gross (4 net) producing and 5 gross (3 net) injection wells in this unit with an average working interest of 64%. As of June 30, 2012, our properties in this unit were producing 605 Boe per day gross, 308 Boe per day net. As of December 31, 2011, the Twin Forks Unit contained 851 MBoe of estimated net proved reserves.

Ardmore West Unit. The Ardmore West Unit is in the Ardmore West Field, an oil-weighted field located in Carter County, Oklahoma. Since its discovery in 1969, the Ardmore West Unit has produced approximately 711 MBoe. Production from the Ardmore West Unit is from the Deese formation at an average depth of approximately 7,000 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 3 gross (3 net) injection wells in this unit with an average working interest of 96%. As of June 30, 2012, our properties in this unit were producing 34 Boe per day gross, 26 Boe per day net. As of December 31, 2011, the Ardmore West Unit contained 750 MBoe of estimated net proved reserves.

Southeast Hewitt Unit. The Southeast Hewitt Unit is in the SE Wilson Field, an oil-weighted field located in Carter County, Oklahoma. Since its discovery in 1979, the Southeast Hewitt Unit has produced approximately 1,663 MBoe. 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. Mid-Con Energy I, LLC acquired a working interest in the SE Hewitt Unit in November 2004, and Mid-Con Energy Operating became the operator of the unit in May 2010. We own 10 gross (2 net) producing and 6 gross (1 net) injection wells in this unit with an average working interest of 24%. As of June 30, 2012, our properties in this unit were producing 217 Boe per day gross, 37 Boe per day net. As of December 31, 2011, the Southeast Hewitt Unit contained 137 MBoe of estimated net proved reserves.

Northeastern Oklahoma

Cleveland Field. The Cleveland Field is an oil-weighted field located in Pawnee County, Oklahoma. Since its discovery in 1904, the entire Cleveland Field has produced approximately 47 MMBoe. Production from the Cleveland Field is primarily from the multiple Pennsylvanian age sands at depths from 1,000 to 2,400 feet. Waterflooding in the Cleveland Field was initiated in most areas by about 1960, although waterflood pilot testing began on some leases prior to 1960. Approximately 1,880 gross acres in the Cleveland Field is being operated by our affiliate, Mid-Con Energy Operating. Approximately 1,000 of the total 1,880 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 in net production within the last two years. The majority of Mid-Con Energy Operating operated leases are produced under waterflood. Mid-Con Energy Operating operates 108 gross (105 net) producing wells, 27 gross (26 net) injection wells and 2 gross (2 net) recently drilled but not completed wells in this field with an average working interest of 97%. As of June 30, 2012, our properties in this field were producing 357 Boe per day gross, 299 Boe per day net. As of December 31, 2011, our leases within the Cleveland Field contained 1,959 MBoe of estimated net proved reserves.

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. Since its discovery in 1912, the entire Cushing Field has produced in excess of 500 MMBoe, with our leases having produced approximately 9,575 MBoe. Production from the Cushing Field is primarily from multiple Pennsylvanian age sands at depths from 1,200 to 2,500 feet. Waterflooding in the Cushing field was initiated in some areas by about 1955, although waterflood pilot testing began on some leases as early as 1949. 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 are currently engaged in a drilling program on this property to develop additional reserves. We operate 75 gross (29 net) producing, 39 gross (14 net) injection and 2 gross (1 net) recently drilled but not completed wells in this field with an average working interest of 37%. As of June 30, 2012, our properties in this field were producing 320 Boe per day gross, 101 Boe per day net. As of December 31, 2011, our leases within the Cushing Field contained 765 MBoe of estimated net proved reserves.

Skiatook Project. The Skiatook Waterflood Project is in the Skiatook Field, an oil-weighted field located in Osage County, Oklahoma. Since its discovery in 1919, the Skiatook Field has produced approximately 1,184 MBoe. 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%. As of June 30, 2012, our properties in this field were producing 43 Boe per day gross, 36 Boe per day net. As of December 31, 2011, our properties in the Skiatook Project contained 426 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. The War Party I and II Units were formed as waterflood units in 2001 and 2002, respectively. War Party I and II Units have collectively produced approximately 5,464 MBoe since discovery. 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 I Unit and War Party II Unit, respectively, and production response to injection started in February 2002 and March 2003 for War Party I Unit and War Party II Unit, respectively. We own 26 gross (18 net) producing, 13 gross (9 net) injection, 8 gross (5 net) shut-in and 3 gross (2 net) recently drilled but not completed wells in both units with an average working interest in War Party I of 86% and in War Party II of 54%. As of June 30, 2012, our properties in these units were producing 268 Boe per day gross, 160 Boe per day net. As of December 31, 2011, our properties in the War Party I and II Units together contained 742 MBoe of estimated net proved reserves.

Harker Ranch Unit. The Harker Ranch Unit is in the Harker Ranch Field, an oil-weighted field located in Cheyenne County, Colorado. Since its discovery in 1989, the Harker Ranch Unit has produced over 1,082 MBoe. 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 3 gross (3 net) producing and 2 gross (2 net) injection wells in this unit with a working interest of 100%. As of June 30, 2012, our properties in this unit were producing 72 Boe per day gross, 59 Boe per day net. As of December 31, 2011, the Harker Ranch Unit contained 318 MBoe of estimated net proved reserves.

Other Properties

Decker Unit. The Decker Unit is in the NW Little Field, an oil-weighted field located in Seminole County, Oklahoma. Since its discovery in 1954, the Decker Unit has produced approximately 575 MBoe. 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 6 gross (6 net) producing and 4 gross (4 net) injection wells in this unit with an average working interest of 98%. As of June 30, 2012, our properties in this unit were producing 24 Boe per day gross, 19 Boe per day net. As of December 31, 2011, the Decker Unit contained 216 MBoe of estimated net proved reserves.

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, 2011, our other properties contained 120 MBoe of estimated net proved reserves and generated average net production of 57 Boe per day for the month ended June 30, 2012.

Oil and Natural Gas Reserves and Production

Internal Controls Relating to Reserve Estimates

Our proved reserves are estimated at the well or unit level and compiled for reporting purposes by our reservoir engineering staff. Reserves are reviewed internally by our senior management on a quarterly basis. Cawley, Gillespie & Associates, Inc., our independent reserve engineers, audits our reserve estimates at least annually.

Our staff works closely with Cawley, Gillespie & Associates, Inc. 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 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 are considered to be analogous based on production performance from the same formation and similar completion techniques.

Table of Contents

Qualifications of Responsible Technical Persons

Internal Mid-Con Energy Operating Person. Robbin W. Jones, P.E., Vice President and Chief Engineer of our general partner, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Mr. Jones has over 30 years of industry experience with positions of increasing responsibility in management, production, reservoir engineering and reserve evaluations with companies such as Enserch Exploration, Caruthers Producing, Diamond Energy Operating Company, Equinox Oil Company and Schlumberger Data & Consulting Services. In 1981, he received a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa. He is a Registered Professional Engineer in the States of Louisiana and Texas and a member of the Society of Petroleum Engineers.

Cawley, Gillespie & Associates, Inc. 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 not performed other work for the Mid-Con Affiliates or Mid-Con Energy Operating. 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 and the standardized measure amounts associated with our estimated proved reserves attributable to our properties as of December 31, 2011 based on a reserve report prepared by our reservoir engineering staff and audited by Cawley, Gillespie & Associates, Inc.

	December 31, 2011
Reserve Data(1):	
Estimated proved reserves (MBoe)	10,049
Estimated proved developed reserves (MBoe)	6,948
Estimated proved undeveloped reserves (MBoe)	3,101
Standardized Measure (in millions)(2)	$ 328

(1) Our estimated net proved reserves and related standardized measure were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $96.19 per Bbl for oil and $4.11 per MMBtu for natural gas at December 31, 2011. 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.

(2) Standardized measure is calculated in accordance with Statement of Financial Accounting Standards No. 69 Disclosures About Oil and Gas Producing Activities, as codified in ASC Topic 932, *Extractive*

Table of Contents

Activities 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.

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, please read Risk Factors Risks Related to Our Business 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.

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 shown above 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.

Changes in Total Proved and Proved Developed Reserves

These reserve estimates were prepared in accordance with the SEC s rules regarding oil and natural gas reserve reporting that are currently in effect. From December 31, 2010 to December 31, 2011 our proved reserves increased by approximately 2.9 MMBoe, or 41%. Total proved reserves increased by approximately 0.9 MMBoe from acquisitions in the Hugoton Basin and Northeastern Oklahoma core areas; 0.8 MMBoe from waterflood expansion in the Northeastern Oklahoma core area; 0.7 MMBoe from infill drilling in Southern Oklahoma core areas; 0.7 MMBoe from drilling and workovers in Northeastern Oklahoma and the Hugoton Basin core area and (0.3) MMBoe in net performance revisions for all of our properties. We spent a total of $19.3 million and $30.0 million in capital expenditures for the year ended December 31, 2010 and the year ended December 31, 2011, respectively, which contributed to the increase in our December 31, 2011 proved reserves.

From December 31, 2010 to December 31, 2011, our proved developed reserves increased by approximately 3.1 MMBoe, or 87%. Proved developed reserves increased in our Southern Oklahoma core area by 0.9 MMBoe from development drilling and 0.7 MMBoe in performance revisions; in the Hugoton Basin core area by 0.7 MMBoe from the acquisition of the War Party I and II Units; in our Northeastern Oklahoma core area by 0.2 MMBoe from acquisitions, 0.7 MMBoe from infill drilling and workovers and (0.1) MMBoe in net performance revisions for the Hugoton Basin and Northeastern Oklahoma core areas and other properties.

During the year ended December 31, 2011, we spent approximately $21.9 million in our Southern Oklahoma core area resulting in production increases and reclassifications of 0.9 MMBoe from proved undeveloped reserves to proved developed reserves, which contributed to the 1.6 MMBoe increase in proved developed reserves in our Southern Oklahoma core area disclosed in the prior paragraph. Additionally, we spent approximately $13.2 million during the year ended December 31, 2011 to acquire

Table of Contents

new leases in the Hugoton Basin and Northeastern Oklahoma. We spent another $2.4 million on workover activities and $3.4 million on drilling during the year ended December 31, 2011 in Northeastern Oklahoma.

Development of Proved Undeveloped Reserves

The following table represents a summary of activity within our proved undeveloped reserve category for the year ended December 31, 2011:

	Oil (MBbl)	Gas (MMcf)	Total (MBoe)
Proved undeveloped reserves-beginning of year	3,406	0	3,406
Transferred to proved developed through drilling	(950)	(7)	(951)
Increase (decrease) due to evaluation reassessments and drilling results, net	481	(12)	479
Acquisition of reserves	164	0	164
Reduction of proved developed reserves aged five or more years	0	0	0
Proved undeveloped reserves-end of year	3,101	(19)	3,098

None of our proved undeveloped reserves at December 31, 2011 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. Historically, our capital expenditures were substantially funded from investment capital, bank debt and cash flow from operations. 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 2011, our capital expenditures for development drilling were approximately $24.5 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 credit facility. For a more detailed discussion of our liquidity position, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Table of Contents

Production, Revenues and Price History

The following table sets forth information regarding combined net production of oil and certain price and cost information based on historical information for each of the periods presented:

	Mid-Con Energy Corporation (consolidated)	Mid-Con Energy Partners, LP				
	Year Ended June 30, 2009	Six Months Ended December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2011	Six Months Ended June 30, 2011	Six Months Ended June 30, 2012
Production and operating data: Net production volumes:						
Oil (MBbls)	153	87	228	407	167	304
Natural gas (MMcf)	341	140	191	164	79	60
Total (MBoe)	210	110	260	434	180	314
Average net production (Boe/d)	575	602	710	1,191	994	1,725
Average sales price:(1)						
Oil (per Bbl)	$ 66.87	$ 65.85	$ 73.92	$ 90.45	$ 93.47	$ 95.39
Natural gas (per Mcf)	$ 6.37	$ 5.31	$ 7.42	$ 7.43	$ 8.33	$ 5.88
Average price per Boe	$ 59.13	$ 58.84	$ 70.27	$ 87.63	$ 90.37	$ 93.47
Average unit costs per Boe:						
Oil and natural gas production expenses	$ 25.56	$ 22.10	$ 23.99	$ 19.56	$ 19.72	$ 15.05
Production taxes	$ 3.00	$ 2.45	$ 3.16	$ 4.31	$ 3.64	$ 2.27
General and administrative and other	$ 8.41	$ 6.40	$ 3.78	$ 4.43	$ 2.97	$ 15.51
Depreciation, depletion and amortization	$ 10.01	$ 21.43	$ 20.02	$ 15.66	$ 11.56	$ 15.00

(1) Prices do not include the effects of derivative cash settlements.

Development Activities

In December 2011, we substantially completed an extensive program that we originally undertook in January 2010 which consisted of drilling approximately 83 gross (52 net) development wells, mostly in our Southern Oklahoma core area. Approximately 70% of these development wells are producing wells, and the remainder are injection wells. The program has successfully increased injection and production. We expect that this program will result in modest future capital expenditure requirements.

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 since 1985. These acquisitions have resulted in an approximately doubling of our acreage position in the field. Our exploitation program has consisted of drilling new wells, returning wells to production on acquired leases, recompleting shallower horizons and expanding waterflood operations to include previously unflooded reservoirs.

Effective June 1, 2011, we acquired two waterflood units, War Party I and II Units, in our Hugoton Basin core area. We engaged in a workover program to return a number of inactive wells in these units to

Table of Contents

production, to optimize producing well rates and to increase injection. This program was substantially completed on October 31, 2011.

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,						Six Months Ended	
	2009		2010		2011		2012	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development wells:								
Productive	7	2	21	13	34	21	11	7
Injection	1	1	10	5	12	9	3	2
Dry			4	2	2	1	0	0
Exploratory wells:								
Productive							0	0
Dry							0	0
Total wells:								
Productive	7	2	21	13	34	21	11	7
Injection	1	1	10	5	12	9	3	2
Dry			4	2	2	1	0	0
Total	**8**	**3**	**35**	**20**	**48**	**31**	**14**	**9**

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 1 gross (1 net) recently drilled well in our Southern Oklahoma core area and 1 gross (1 net) recently drilled well in our Northeastern Oklahoma core area.

Productive Wells

The following table sets forth information at June 30, 2012 relating to the productive wells in which we owned a working interest as of that date. 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		Shut-in/ Waiting on Completion		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated	314	222	1	1	149	97	13	10	81	67	558	397
Non-operated	1	0	4	1	0	0	0	0	0	0	5	1
Total	**315**	**222**	**5**	**2**	**149**	**97**	**13**	**10**	**81**	**67**	**563**	**398**

90

Table of Contents

Developed Acreage

The following table sets forth information as of June 30, 2012 relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table. As of June 30, 2012 substantially all of our leasehold acreage was held by production.

	Developed Acreage	
	Gross	**Net**
Southern Oklahoma	8,664	5,214
Northeastern Oklahoma	6,319	3,939
Hugoton Basin	5,952	4,373
Other	1,281	763
Total	**22,216**	**14,289**

Delivery Commitments

We will have no delivery commitments with respect to our production upon the closing of this offering.

Operations

General

Mid-Con Energy Operating operated approximately 99% of our properties, as calculated on a Boe basis as of December 31, 2011. 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.

Our affiliate, Mid-Con Energy Operating, provides certain services to us, including management, administrative, operational, marketing, geological and engineering services, pursuant to a services agreement.

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 27 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. Based on the standardized measure, our value-weighted average net revenue interest on our properties was approximately 81.8%, on a 100% working interest basis, based on our December 31, 2011 audited reserves. Most of our leases are held by production and do not require lease rental payments.

Marketing and Major Customers

For the year ended December 31, 2011, purchases by Sunoco Logistics accounted for approximately 86% of our total sales revenues. In 2012, we entered into crude oil purchase agreements with Enterprise, Vitol and Coffeyville Resources. For the six months ended June 30, 2012, sales to Enterprise, Sunoco Logistics and Vitol accounted for approximately 54%, 37% and 2%, respectively, of our total sales. We do not currently sell any production to Sunoco Logistics. After June 30, 2012, we expect that Vitol and Coffeyville Resources will each account for significantly higher percentages of our total sales. By selling our 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 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. For a discussion of risks associated with our relationship with our significant customers, please read Risk Factors Risks Related to Our Business. 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 lost any of those customers.

Hedging Activities

We intend 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. Our

Table of Contents

current commodity derivative contracts are primarily fixed price swaps (with collars) with NYMEX prices and option agreements. For a more detailed discussion of our hedging activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and Management s Discussion and Analysis of Financial Condition and Results of Operations 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 prices 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 in all material respects as described in this prospectus.

Table of Contents

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 32% of our total estimated proved reserves as of December 31, 2011, 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. Of our $5.0 million of estimated maintenance capital expenditures for the year ended December 31, 2012, approximately $0.6 million is expected to be attributable to hydraulic fracturing.

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, a 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.

Table of Contents

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, or 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 clean up 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 Environmental Matters and Regulation Hydraulic Fracturing. For related risks to our unitholders, please read 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 million and $5 million per occurrence, respectively, and $2 million and $5 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 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.

Table of Contents

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, state, tribal 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 well sites. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of orders enjoining performance of some or all of our operations.

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

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, drilling, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. 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, or 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 federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, or CERCLA, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or legality of conduct, on certain classes of persons who are 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 entities that 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 under CERCLA.

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, leased or operated 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 or release 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, or 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. 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. SPCC 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 require 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, 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

Table of Contents

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, or 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 relating 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 begun the process of drafting 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. 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, including Texas, 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 required certain oil and gas operators to cease water injection associated with 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. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation 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, with initial results expected to be available by late 2012 and final results 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

Table of Contents

better protect the environment from drilling using hydraulic fracturing completion methods. The U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. 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 April 17, 2012, the EPA approved 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. The EPA has adopted two sets of regulations under the Clean Air Act. The first requires a reduction in emissions of GHGs from motor vehicles. The second requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. On May 12, 2010, the EPA also issued a new tailoring rule, which makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the Clean Air Act. On September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. In addition, on November 30, 2010, the EPA published a final rule that expands its existing GHG emissions reporting rule to include certain owners and operators of onshore oil and natural gas production to monitor GHG emissions beginning in 2011 and to report those emissions beginning in 2012. 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, or 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, as amended, or ESA, may restricts activities that may 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.

Table of Contents

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or 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, or 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, or FTC, and the 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, natural gas liquids, 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. 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, 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 the State of 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. Increased federal and state safety regulation could affect the availability and cost of pipeline transportation to us.

At the federal level, on January 3, 2012, President Obama signed the 2011 Pipeline Safety Act, which act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the

Table of Contents

U.S. Secretary of Transportation to evaluate or promulgate stricter safety rules or standards for liquids and gas interstate pipelines. On August 13, 2012, the federal Pipeline and Hazardous Materials Safety Administration, or PHMSA, published a proposed rulemaking consistent with the signed act that, once finalized, will increase the maximum administrative civil penalties for violation of the pipeline safety laws and regulations after January 3, 2012 to $200,000 per violation per day of violation, with a maximum of $2,000,000 for a related series of violations. In addition, PHMSA published a final rule in May 2011 expanding pipeline safety requirements including added reporting obligations and integrity management standards to certain rural low-stress hazardous liquid pipelines that were not previously regulated in such manner. In August 2011 and October 2010, PHMSA published advance notices of proposed rulemakings with respect to gas and oil pipelines respectively, in which the agency is seeking public comment on a number of changes to regulations governing pipeline safety, and, in May 2012, PHMSA issued an advisory bulletin regarding the adequacy of records that could result in reduced operating pressures on certain pipelines.

Numerous state agencies have been certified to enforce the federal rules and standards, and state agencies often adopt and enforce state-wide safety rules and standards governing intrastate pipelines, which may be as restrictive or more restrictive than the federal rules and standards. Similar to federal regulation, state regulation has become increasingly stringent in recent years and state regulation may continue to increase in the immediate future.

Employees

The officers of our general partner manage our operations and activities. Neither we, our subsidiary, nor our general partner have employees. Mid-Con Energy Operating performs services for us, including the operation of our properties, pursuant to the services agreement between it and our general partner. Please read Certain Relationships and Related Party Transactions Services Agreement. Mid-Con Energy Operating has more than 65 employees performing services for our operations and activities. We believe that Mid-Con Energy Operating has a satisfactory relationship with those employees.

Offices

Our headquarters are located at 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201, with approximately 3,853 square feet of office space under lease. Our Dallas lease expires in 2016. For our principal operating office, we currently lease approximately 13,545 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.

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.

Table of Contents

MANAGEMENT

Management of Mid-Con Energy Partners, LP

Our general partner manages our operations and activities on our behalf through its executive officers and board of directors. References in this prospectus 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, each of whom will be appointed by the Founders, 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. Please read Conflicts of Interest and Fiduciary Duties Fiduciary Duties.

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. Please read Director Independence and Committees of the Board of Directors below.

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. Please read Certain Relationships and Related Party Transactions Services Agreement. We expect the executive officers of our general partner and other shared personnel to devote a sufficient amount of time to our business and affairs as is necessary for the proper management and conduct of our business and operations. However, the executive officers of our general partner and other shared personnel also devote substantial amounts of their time to managing the businesses of the Mid-Con Affiliates.

Directors and Executive Officers of Mid-Con Energy GP, LLC

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	35	President, Chief Financial Officer and Director
David A. Culbertson	47	Vice President and Chief Accounting Officer
Robbin W. Jones	53	Vice President and Chief Engineer
Nathan P. Pekar	36	Vice President, General Counsel and Secretary
Peter A. Leidel	56	Director
Cameron O. Smith	62	Director
Robert W. Berry	88	Director
Peter Adamson III	71	Director

Table of Contents

The members of our general partner s 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 partner s 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 partner s executive officers and directors. In evaluating director candidates, the Founders will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the ability of the board of directors to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the board to fulfill their duties. While the Founders may consider diversity among other factors when considering director nominees, they do not apply any specific diversity policy with regard to selecting and appointing directors to the board of directors. However, when appointing new directors, the Founders will consider each individual director s qualifications, skills, business experience and capacity to serve as a director, and the diversity of these attributes for the board of directors as a whole.

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 previously a member of the board of directors of Mid-Con Energy I, LLC following its formation in 2004 and of Mid-Con Energy II, LLC since its formation in 2009. 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. We believe that Mr. George s service as the chief executive officer and a director of a publicly traded exploration and production company brings important experience and leadership skill to the board of directors of our general partner.

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 previously served as President, Chief Financial Officer and Chairman of the board of directors of Mid-Con Energy I, LLC following its formation in 2004 and of Mid-Con Energy II, LLC following its formation in 2009. 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. We believe that Mr. Olmstead s extensive experience in the oil and gas industry brings important experience and leadership skill to the board of directors of our general partner.

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 and of Mid-Con Energy Operating since 2007. Mr. Olmstead was previously a member of the board of directors of Mid-Con Energy I, LLC and of Mid-Con Energy II, LLC following its formation. 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

Table of Contents

of Texas/Bank of Oklahoma in the bank s energy group. 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. We believe that Mr. Olmstead s experience in energy-related finance brings important experience and leadership skill to the board of directors of our general partner.

David A. Culbertson serves as Vice President and Chief Accounting Officer of our general partner. Mr. Culbertson previously served as Controller of Mid-Con Energy I, LLC after 2006 and of Mid-Con Energy II, LLC following its formation in 2009. 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.

Robbin W. Jones, P.E. serves as Vice President and Chief Engineer of our general partner. Mr. Jones was elected President of Mid-Con Energy III, LLC in June 2011. Mr. Jones previously served as a Vice President and Chief Operating Officer of the predecessor and affiliate companies since 2007. Mr. Jones served as reservoir engineer and manager of our Houston office from March 2005, when he joined our predecessor, until 2007. Mr. Jones served as manager at Schlumberger Data & Consulting Services from 2004 to 2005 and has twenty years of engineering experience in all phases of waterflood development and management working for Enserch Exploration, Caruthers Producing, Diamond Energy Operating Company and Equinox Oil Company. Mr. Jones received a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa. He is a Registered Professional Engineer in the states of Louisiana and Texas and a member of the Society of Petroleum Engineers.

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 in positions of increasing responsibility, and ultimately as General Counsel and Business Development Manager with Matador Resources Company from 2007-2012, during which time he assisted it in becoming a public company. Prior to this, Mr. Pekar was in private practice from 2003 to 2007. Mr. Pekar is a graduate of The University of Texas, with a Bachelor of Business Administration degree in Finance, and of Southern Methodist University, 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 has been a member of the board of directors of Mid-Con Energy I, LLC since its formation in 2004 and of Mid-Con Energy II, LLC since its formation in 2009. 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. We believe that Mr. Leidel s extensive financial and private investment experience, as well as his experience on the boards of directors of numerous public and private companies (including prior service as the chairman of the audit committees of two public companies), bring substantial leadership skill and experience to the board of directors.

Table of Contents

Cameron O. Smith serves as a member of the board of directors of our general partner. In January 1992, Mr. Smith founded, and until June 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 when it was sold to Rodman & Renshaw, LLC, a full service investment bank. From 2008 until December 2009, Mr. Smith served Rodman & Renshaw, LLC as a Senior Managing Director and Head of The Rodman Energy Group. Between January 2010 and late 2011, Mr. Smith enjoyed a sabbatical from business. Toward the end of 2011, Mr. Smith re-engaged in the oil and gas business, joining our general partner s board of directors and accepting a position as Senior Advisor to the Energy Group of Warburg Pincus LLC, a large private equity fund based in New York City. From 1975 until 1978, Mr. Smith worked as an exploration geologist for various public oil companies founded by his family. In 1978, he formed his own exploration company, Taconic Petroleum corporation, headquartered in Tulsa, Oklahoma, which he ran until the end of 1991. Mr. Smith received a Master of Science in Geology degree from Pennsylvania State University in 1975 and an A.B. in Art History from Princeton University in 1972. We believe that Mr. Smith s extensive financial and private equity experience, as well as his experience in the oil and natural gas industry generally, bring substantial leadership skill and experience to the 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. We believe that Mr. Berry s extensive experience in the oil and gas industry brings substantial leadership skill and experience to the board of directors of our general partner.

Peter Adamson III serves as a member of the board of directors of our general partner. Mr. Adamson is a founder of Adams Hall Asset Management LLC, a Tulsa, Oklahoma based registered investment advisor with over $1 billion under management, to which he now functions as a consultant. Prior to forming Adams Hall in 1997, Mr. Adamson was an owner and principal of Houchin, Adamson & Co., Inc., a registered broker-dealer formed in 1980. Mr. Adamson is founding co-investor and advisor to Horizon Well Logging, a leading provider of geological field services. Mr. Adamson serves on the advisory board of the Michel F. Price College of Business at the University of Oklahoma and serves on the University of Oklahoma asset oversight committee. Mr. Adamson received his Bachelor of Business Administration degree in accounting from the University of Oklahoma. We believe that Mr. Adamson s extensive financial and investing experience bring substantial leadership skill and experience to the board of directors.

Reimbursement of Expenses of Our General Partner

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and our other affiliates, including Mid-Con Energy Operating, may be reimbursed. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.

Mid-Con Energy Operating provides management, administrative and operational services to us pursuant to a 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 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. For further discussion of the reimbursements that Mid-Con Energy Operating will be entitled to receive relating to services provided in connection with the services agreement, please read Certain Relationships and Related Party Transactions Services Agreement.

Director Independence

Messrs. Berry, Smith and Adamson meet the independence standards established by the NASDAQ listing rules.

Committees of the Board of Directors

The board of directors of our general partner has an audit committee and a conflicts committee. We do not have a compensation committee, but rather an appointed committee approves equity grants to directors and employees. As noted above, the NASDAQ listing rules do not require a listed limited partnership to establish a compensation committee or a nominating and corporate governance committee.

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NASDAQ listing rules and rules of the SEC. 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 also is 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. Currently, Messrs. Berry, Smith and Adamson serve on the audit committee.

Conflicts Committee

Our partnership agreement requires that at least two independent members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board of directors believes may involve conflicts of interest (including certain transactions with affiliates of our general partner, including the Mid-Con Affiliates) and that it determines to submit to the conflicts committee for review. Our general partner may, but is not required to, seek approval from the conflicts committee of a resolution of a conflict of interest with our general partner or affiliates. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, including the Mid-Con Affiliates or holders of any ownership interest in our general partner or any of its affiliates, other than common units or securities exercisable, convertible into or exchangeable for common units, and must meet the independence standards established by the NASDAQ listing rules and the Securities Exchange Act of 1934 to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the conflicts committee will be conclusively deemed to have been approved in good faith. In addition, any such matters will be deemed to be approved by all of our partners and not constitute a breach of our partnership agreement or of any duties our general partner may owe us or our unitholders. Please read Conflicts of Interest and Fiduciary Duties Conflicts of Interest. Currently, Messrs. Berry, Smith and Adamson serve on the conflicts committee.

Table of Contents

Board Leadership Structure and Role in Risk Oversight

Leadership of our general partner s board of directors is vested in a Chairman of the Board. Although our Chief Executive Officer currently does not serve as Chairman of the Board of Directors of our general partner, we currently have no policy prohibiting our current or any future chief executive officer from serving as Chairman of the Board. The board of directors, in recognizing the importance of its ability to operate independently, determined that separating the roles of Chairman of the Board and Chief Executive Officer is advantageous for us and our unitholders. Our general partner s board of directors has also determined that having the Chief Executive Officer serve as a director could 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 may be defined as the process of identification, management 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 will offer an enterprise-level risk assessment to the board of directors at least once every year.

We and our general partner were formed in July 2011. The executive officers of our general partner are also executive officers and/or directors of the Mid-Con Affiliates. These executive officers devote a sufficient amount of time to our business and affairs as is necessary for the proper management and conduct of our business and operations. However, these executive officers also devote substantial amounts of time to managing the businesses of the Mid-Con Affiliates. The executive officers of our general partner currently devote their business time to our business as follows: S. Craig George, Charles R. Olmstead, Jeffrey R. Olmstead, David A. Culbertson, and Robbin W. Jones devote approximately 80%, $66^2/_3$%, 80%, $66^2/_3$% and 50% of their business time, respectively. The amount of time that each of our executive officers devotes to our business is subject to change depending on our activities, the activities of the Mid-Con Affiliates to which they also provide services, and any acquisitions or dispositions made by us or the Mid-Con Affiliates.

Because the executive officers of our general partner are employees of Mid-Con Energy Operating, their compensation is paid by Mid-Con Energy Operating and we reimburse Mid-Con Energy Operating pursuant to the services agreement for the portion of such compensation allocable to us. Please read Certain Relationships and Related Party Transactions Services Agreement.

Compensation Committee Interlocks and Insider Participation

The NASDAQ listing rules do not require a listed limited partnership to establish 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 Discussion and Analysis

This Compensation Discussion and Analysis provides information regarding the executive compensation program for our Chief Executive Officer, our Chief Financial Officer and our three executive officers (other than the Chief Executive Officer and Chief Financial Officer) who were the most highly compensated executives at the end of the last completed fiscal year, or the named executive officers.

The following individuals were our named executive officers as of December 31, 2011:

- Charles R. Olmstead, Chief Executive Officer;
- S. Craig George, Executive Chairman of the Board;

Table of Contents

Jeffrey R. Olmstead, President, Chief Financial Officer;

David A. Culbertson, Vice President, Chief Accounting Officer; and

Robbin W. Jones, Vice President and Chief Engineer.

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 will reimburse our general partner for payments it makes to Mid-Con Energy Operating. Please read Certain Relationships and Related Party Transactions Services Agreement and Reimbursement of Expenses of Our General Partner.

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 predecessor historically compensated its executive officers primarily with base salary and cash bonuses.

Our general partner also grants equity-based awards to our executive officers pursuant to a long-term incentive program. Annual bonuses payable to our executive officers will be determined based on our financial performance as measured across a fiscal year. However, incentive compensation in respect of services provided to us will not be tied in any way to the performance of entities other than our partnership. Specifically, any performance metrics will not 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 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 short 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

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. 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 long-term incentive program is approximately 1.8 million units. As of December 31, 2011 all of the units were available for issuance.

Table of Contents

Equity Compensation Program Information

Long-term incentive program category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			1,464,451 common units
Equity compensation plans not approved by security holders			0
Total			1,464,451 common units

On January 31, 2012 and July 31, 2012, a committee administrating the program awarded units under the long-term incentive program. This committee awarded units to our executive officers, key employees, consultants and outside directors in an amount equal to 62,049 restricted units and 237,500 unrestricted units.

For additional information regarding the long-term incentive program, see Long-Term Incentive Program.

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 our initial public offering and 50% earned upon causing us to comply with current public reporting requirements of the Securities and Exchange Act of 1934 for at least six months. The performance criteria for the short-term incentive plan for 2012 includes, and for future years are expected to 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 of directors. We do not provide perquisites to the named executive officers.

Table of Contents

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 year ended December 31, 2011. Our named executive officers are paid by Mid-Con Energy Operating. We reimburse Mid-Con Energy Operating for a portion of its compensation according to the Services Agreement. There was not a service agreement in place prior to December 2011; therefore, no salaries or other compensation were allocated prior to December 2011.

Name and Principal Position	Year	Salary	Bonus	Unit Awards	All Other Compensation	Total
Charles R. Olmstead	2011	$ 15,361				$ 15,361
Chief Executive Officer						
S. Craig George	2011	$ 17,270				$ 17,270
Executive Chairman of the Board						
Jeffrey R. Olmstead	2011	$ 27,024				$ 27,024
President, Chief Financial Officer						
David A. Culbertson	2011	$ 11,668				$ 11,668
Vice President, Chief Accounting Officer						
Robbin W. Jones	2011	$ 12,402				$ 12,402
Vice President, Chief Engineer						

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.

Table of Contents

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, or 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

Table of Contents

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, 2011, 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	Termination Following Change in Control
Cash Severance	$ 640,000	$ 480,000	$ 480,000
Equity			
Restricted Stock/Units			
Performance Shares/Units	917,500	917,500	917,500
Total	1,557,500	1,397,500	1,397,500
Other Benefits			
Health & Welfare	15,428	15,428	15,428
Tax Gross-Ups			
Total	15,428	15,428	15,428
Total	$ 1,572,928	$ 1,412,928	$ 1,412,928

Charles R. Olmstead	Termination Upon Death, Disability or Retirement	Termination Without Cause	Termination Following Change in Control
Cash Severance	$ 640,000	$ 480,000	$ 480,000
Equity			
Restricted Stock/Units			
Performance Shares/Units	917,500	917,500	917,500
Total	1,557,500	1,397,500	1,397,500
Other Benefits			
Health & Welfare	15,428	15,428	15,428
Tax Gross-Ups			
Total	15,428	15,428	15,428
Total	$ 1,572,928	$ 1,412,928	$ 1,412,928

Table of Contents

Jeffrey R. Olmstead	Termination Upon Death, Disability or Retirement	Termination Without Cause	Termination Following Change in Control
Cash Severance	$ 760,000	$ 720,000	$ 720,000
Equity			
Restricted Stock/Units			
Performance Shares/Units	917,500	917,500	917,500
Total	1,677,500	1,637,500	1,637,500
Other Benefits			
Health & Welfare	21,182	21,182	21,182
Tax Gross-Ups			
Total	21,182	21,182	21,182
Total	$ 1,698,682	$ 1,658,682	$ 1,658,682

Long-Term Incentive Program

Our general partner adopted a long-term incentive program for employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating, who perform services for us.

The description of the long-term incentive program set forth below is a summary of the material features of the program. This summary, however, does not purport to be a complete description of all of the provisions of the program.

The type of awards that may be granted under the long-term incentive program consists of the following components: restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The purpose of awards under the long-term incentive program is to provide additional incentive compensation, at the discretion of the board or a compensation committee if the board elects to form such a committee, to employees providing services to us, and to align the economic interests of such employees with the interests of our unitholders. The long-term incentive program currently limits the number of units that may be delivered pursuant to awards to 1,764,000 common units. Common units cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The program is currently administered by a committee consisting of the Founders, which is referred to as the program administrator. The program administrator may also delegate its duties as appropriate.

Amendment or Termination of Long-Term Incentive Program

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

Table of Contents

Restricted Units

A restricted unit is a common unit that vests over a period of time, and during that time, is subject to forfeiture. Forfeiture provisions lapse at the end of the vesting period. The program administrator may make grants of restricted units containing such terms as it shall determine, including the period over which restricted units will vest. The program administrator, in its discretion, may base its determination upon the achievement of specified financial or other performance objectives. Restricted units will be entitled to receive quarterly distributions during the vesting period.

We intend the restricted units under the program to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common units. Therefore, program participants will not pay any consideration for restricted units they receive, and we will receive no remuneration for the restricted units.

Phantom Units

A phantom unit is a notional common unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the program administrator, cash equivalent to the value of a common unit. The program administrator may make grants of phantom units under the program containing such terms as the program administrator shall determine, including the period over which phantom units granted will vest. The program administrator, in its discretion, may base its determination upon the achievement of specified financial or other performance objectives.

We intend the issuance of any common units upon vesting of the phantom units under the program to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common units. Therefore, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the common units.

Unit Options

The long-term incentive program permits the grant of options covering common units. Unit options represent the right to purchase a designated number of common units at a specified price. The program administrator may make grants containing such terms as the program administrator shall determine. Unit options will have an exercise price that is not less than the fair market value of the common units on the date of grant. In general, unit options granted will become exercisable over a period determined by the program administrator.

Unit Appreciation Rights

The long-term incentive program permits the grant of unit appreciation rights. A unit appreciation right is an award that, upon exercise, entitles the participant to receive the excess of the fair market value of a common unit on the exercise date over the exercise price established for the unit appreciation right. Such excess will be paid in cash or common units. The program administrator may make grants of unit appreciation rights containing such terms as the program administrator shall determine. Unit appreciation rights will have an exercise price that is not less than the fair market value of the common units on the date of grant. In general, unit appreciation rights granted will become exercisable over a period determined by the program administrator.

Table of Contents

Distribution Equivalent Rights

The program administrator may, in its discretion, grant distribution equivalent rights, or DERs, in tandem with phantom unit awards under the long-term incentive program. DERs entitle the participant to receive an amount in cash, units or phantom units equal to the amount of any cash distributions made by us during the period that the phantom unit award is outstanding. Payment of a DER issued in connection with another award may be subject to the same or different vesting terms as the award to which it relates or in the discretion of the program administrator.

Other Unit-Based Awards

The long-term incentive program permits the grant of other unit-based awards, which are awards that are based, in whole or in part, on the value or performance of a common unit. Upon vesting, the award may be paid in common units, cash or a combination thereof, as provided in the grant agreement.

Unit Awards

The long-term incentive program permits the grant of common units that are not subject to vesting restrictions. Unit awards may be in lieu of or in addition to other compensation payable to the individual.

Change in Control and Anti-Dilution Adjustments

Upon a change of control (as defined in the long-term incentive program), any change in applicable law or regulation affecting the long-term incentive program or awards thereunder, or any change in accounting principles affecting the financial statements of our general partner, the program administrator, in an attempt to prevent dilution or enlargement of any benefits available under the long-term incentive program may, in its discretion, provide that awards will (i) become exercisable or payable, as applicable, (ii) be exchanged for cash, (iii) be replaced with other rights or property selected by the program 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 program 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.

Termination of Service

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

Source of Common Units

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

Table of Contents

Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices are intended 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 may 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. Our compensation policies do not encourage excessive and unnecessary risk taking, and ensure that the level of risk is not reasonably likely to have a material adverse effect on the Partnership.

Compensation of Directors

Officers or employees of our general partner or our other affiliates, including Mid-Con Energy Operating, who also serve as directors do not receive additional compensation for their service as a director of our general partner. Each non-employee director is compensated with a combination of cash and units for their service on the board of directors. Each non-employee director has the option to elect to receive either an annual cash retainer of $40,000, paid in quarterly installments of $10,000, or an equivalent number of units issued under our long-term incentive program. In addition, each non-employee director is paid $1,000 per board meeting that the director attends and an annual $5,000 payment if he serves as the Chairman of either the audit committee or the conflicts committee. Each non-employee director is also granted 2,500 units annually under our long-term incentive program. The directors received no compensation in 2011. In January 2012, each director was awarded 2,500 common units of the Partnership.

Table of Contents

SELLING UNITHOLDERS

This prospectus covers the offering for resale of 3,000,000 common units, or 3,600,000, if the underwriters exercise their option to purchase additional common units in full, owned by the Selling Unitholders. These common units were obtained by the Selling Unitholders as partial consideration in respect of the merger of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC into our subsidiary in connection with our initial public offering.

Immediately before this offering, the Selling Unitholders owned 8,691,468 of our outstanding common units, representing an approximate 48.5% limited partner interest in us. Following this offering, the Selling Unitholders will own 5,691,468 common units, or 5,091,468 common units if the underwriters exercise in full their option to purchase additional common units, representing an approximate 30.1% and 26.9% limited partner interest in us, respectively. Please read Security Ownership of Certain Beneficial Owners and Management. For further discussion of the relationships between us, our general partner and Yorktown, please read Certain Relationships and Related Party Transactions.

No offer or sale under this prospectus may be made by a unitholder unless that holder is listed in the table below, in a supplement to this prospectus or in an amendment to the related registration statement that has become effective under the Securities Act.

The Selling Unitholders are not broker dealers registered under Section 15 of the Exchange Act or affiliates of a broker dealer registered under Section 15 of the Exchange Act.

The following table sets forth information relating to the selling unitholders as of October 12, 2012, based on information supplied to us by the Selling Unitholders on or prior to that date. Assuming that the Selling Unitholders sell all of the common units owned or beneficially owned by them that are offered by this prospectus and do not acquire any additional common units following this offering, the Selling Unitholders will not own any common units other than those appearing in the column entitled Common Units Held Following Offering. In addition, the Selling Unitholders may have sold, transferred or otherwise disposed of, or may sell, transfer or otherwise dispose of, at any time and from time to time, common units in transactions exempt from the registration requirements of the Securities Act of 1933 after the date as of which the information is set forth on the table below.

Selling Unitholders(1)	Common Units Held Prior to Offering	Common Units That May Be Offered	Common Units Held Following Offering(2)	Percentage of Outstanding Common Units(3)(4)
Yorktown Energy Partners VI, L.P.	3,166,888	1,093,102	2,073,786	11.0%
Yorktown Energy Partners VII, L.P.	1,583,444	546,551	1,036,893	5.5%
Yorktown Energy Partners VIII, L.P.	3,941,136	1,360,347	2,580,789	13.6%
Yorktown Total	8,691,468	3,000,000	5,691,468	30.1%

(1) Yorktown Energy Partners IX, L.P. owns a 50% interest in Mid-Con Energy Operating. Yorktown IX Company LP is the sole general partner of Yorktown Energy Partners IX, L.P. Yorktown Associates LLC is the sole general partner of Yorktown IX Company LP. Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., and Yorktown Energy Partners VIII, L.P. own common units in us. For more information on the entities that control Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P., please read Security Ownership of Certain Beneficial Owners and Management. In addition, Peter A. Leidel, a principal of Yorktown, serves on the board of directors of our general partner.

(2) Assumes the sale of all common units held by such Selling Unitholders offered by this prospectus.

(3)

Gives effect to the issuance and sale of the 3,000,000 common units we are offering by means of this prospectus and assumes no exercise by the underwriters of their option to purchase additional common units.

(4) Based on 18,939,549 common units outstanding as of the close of this offering.

Table of Contents

SECURITY OWNERSHIP OF CERTAIN

BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our common units that, following this offering and assuming the underwriters do not exercise their option to purchase additional common units, will be 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(1)	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned
Yorktown Energy Partners VI, L.P.(1)(2)	2,073,786	11.0%
Yorktown Energy Partners VII, L.P.(1)(3)	1,036,893	5.5%
Yorktown Energy Partners VIII, L.P.(1)(4)	2,580,789	13.6%
Charles R. Olmstead(5)	690,278	3.6%
Jeffrey R. Olmstead(5)	230,329(6)	1.2%
Nathan P. Pekar(5)	15,000	0.08%
Robbin W. Jones(5)	228,861(7)	1.2%
David A. Culbertson(5)	74,783	0.4%
S. Craig George(5)	204,585	1.1%
Peter A. Leidel(5)	2,500	0.01%
Peter Adamson III(5)	12,500(8)	0.07%
Robert W. Berry(5)	37,500(9)	0.12%
Cameron O. Smith(5)	22,293	0.12%
All named executive officers, directors and director nominees as a group (10 persons)(5)	1,518,629	7.9 %

(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,

Table of Contents

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) Includes Jeffrey R. Olmstead s indirect ownership of 105,097 common units held by the Charles R. Olmstead 2011 Trust. Jeffrey R. Olmstead is a trustee of the Charles R. Olmstead 2011 Trust and has immediate family members who are beneficiaries of the trust. Jeffrey R. Olmstead disclaims beneficial ownership of the securities owned indirectly except to the extent of his pecuniary interest therein.

(7) Includes Robbin W. Jones indirect ownership of 223,861 common units held by the Jones Revocable Trust. Robbin W. Jones is a trustee of the Jones Revocable Trust and has immediate family members who are beneficiaries of the trust. Robbin W. Jones disclaims beneficial ownership of the securities owned indirectly except to the extent of his pecuniary interest therein.

(8) Includes Peter Adamson III s indirect ownership of 10,000 common units held by Cherokee 2000 Investments LLC. Peter Adamson III is the managing member of Cherokee 2000 Investments LLC. Peter Adamson III disclaims beneficial ownership of the securities owned indirectly except to the extent of his pecuniary interest therein.

(9) Includes Robert W. Berry s indirect ownership of 20,000 common units held by Berry Ventures, Inc. Robert W. Berry is the controlling shareholder of Berry Ventures, Inc. Robert W. Berry disclaims beneficial ownership of the securities owned indirectly except to the extent of his pecuniary interest therein.

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.

Table of Contents

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Following this offering, assuming the underwriters do not exercise their option to purchase additional common units, the Founders and Yorktown will own 6,816,660 common units representing an approximate 36.0% limited partner interest in us. In addition, our general partner will own an approximate 2.0% general partner interest in us, evidenced by 360,000 general partner units. These percentages do not reflect any common units that may be issued under the long-term incentive program in the future.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our ongoing operation and liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, were not the result of arm s length negotiations.

Operational Stage

Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions approximately 98.0% to our unitholders, pro rata, and approximately 2.0% to our general partner, based upon their respective limited and general partner interests in us.
Payments to our general partner and its affiliates	Our general partner does not receive a management fee or other compensation for its management of our partnership, but we will reimburse our general partner for all direct and indirect expenses it incurs and payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner may be reimbursed. These expenses include salary, bonus, incentive compensation, employment benefits and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner determines in good faith the expenses that are allocable to us.
Withdrawal or removal of our general partner	In the event of removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the departing general partner s general partner interest for a cash payment equal to the fair market value of such interest. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the departing general partner s general partner interest in us for its fair market value.

Table of Contents

Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Services Agreement

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, operational, marketing, geological and engineering services. Our services agreement was negotiated among affiliated parties and, consequently, is not the result of arm s length negotiations. 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. From the closing of our initial public offering through December 31, 2011, we reimbursed Mid-Con Energy Operating $0.2 million for direct operating expenses. For the six-month period ending June 30, 2012 we reimbursed Mid-Con Energy Operating $1.3 million for direct operating expenses.

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 partner s organizational documents and the provisions of our partnership agreement. The resolution may be determined by disinterested directors, our general partner s board of directors, or the conflicts committee of our general partner s board of directors. Our Code of Business Conduct is on our website www.midconenergypartners.com under our governance section.

The board of directors of our general partner has a standing conflicts committee currently comprised of three independent directors. Our general partner may, but is not required to, seek the approval of the conflicts committee in connection with acquisitions of oil and natural gas properties from the Mid-Con Affiliates or any other affiliates of the general partner. In addition to acquisitions from affiliates of our general partner, the board of directors of our general partner will also determine whether to seek conflicts committee approval to the extent we act jointly to acquire additional oil and natural gas properties with affiliates of our general partner. In the case of any sale of equity or debt by us to an owner or affiliate of an owner of our general partner, we anticipate that our practice will be to obtain the approval of the conflicts committee of the board of directors of our general partner for the transaction. The conflicts committee is entitled to hire its own financial and legal advisors in connection with any matters on which the board of directors of our general partner has sought the conflicts committee s approval.

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.

Table of Contents

CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner, our general partner s affiliates (including the Mid-Con Affiliates) and Yorktown on the one hand, and us and our limited partners, on the other hand. The directors and officers of our general partner have fiduciary duties to manage the business of our general partner in a manner beneficial to its owners. In addition, all of our general partner s executive officers and non-independent directors will continue to have economic interests in affiliates of our general partner, which may lead to additional conflicts of interest. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that modify and limit our general partner s fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions taken that, without those limitations, might constitute breaches of fiduciary duty.

Our general partner will not be in breach of its obligations under our partnership agreement or its duties to us or our unitholders if the resolution of the conflict is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval;
- approved by the vote of the holders of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If the resolution or course of action taken with respect to the conflict of interest satisfies any of the standards set forth in the first, third or fourth bullet points above, then such resolution or course of action will be deemed to be approved by all of our unitholders and, in the case of all four bullet points above, will not constitute a breach of our partnership agreement or of any duties our general partner may owe us or our unitholders.

As required by our partnership agreement, the board of directors of our general partner will maintain a conflicts committee comprised of at least two independent directors. Our general partner may, but is not required to, seek approval from the conflicts committee of a resolution of a conflict of interest with our general partner or affiliates. Any matters approved by the conflicts committee will be conclusively deemed to have been approved in good faith. If our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third or fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith and, in each case, in any proceeding brought by or on behalf of any limited partner or us challenging such approval, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to subjectively believe that he or she is acting in our best interest.

Table of Contents

Affiliates of our general partner are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner (or as general partner or managing member, as the case may be, of another company of which we are a partner or member) or those activities incidental to its ownership of interests in us. However, affiliates of our general partner, including the Mid-Con Affiliates, and Yorktown are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. Additionally, Yorktown, through its investment funds and managed accounts, makes investments and purchases entities in various areas of the oil and natural industry. These investments and acquisitions may include entities or assets that we would have been interested in acquiring.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner, any of its affiliates (including its executive officers, directors and the Mid-Con Affiliates) or Yorktown. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us; provided, however, that such person does not pursue or acquire such opportunity for itself as a result of using confidential or proprietary information provided by or on behalf of us to such person. Therefore, affiliates of our general partner, including the Mid-Con Affiliates, and Yorktown may compete with us for investment opportunities and may own an interest in entities that compete with us.

Our general partner and its affiliates are allowed to take into account the interests of parties other than us in resolving conflicts of interest.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include our general partners limited call right, its registration rights and its determination whether or not to consent to any merger or consolidation involving us.

All of the executive officers and non-independent directors of our general partner spend significant time serving entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

To maintain and increase our levels of production, we will need to acquire oil and natural gas properties. 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 devote significant time to those businesses. Further, all of our executive officers and non-independent directors have economic interests in, as well as management and fiduciary duties to, the Mid-Con Affiliates. The existing positions held by these directors and officers may give rise to fiduciary duties that are in conflict with fiduciary duties they owe to us. We cannot assure our unitholders that these conflicts will be resolved in our favor. As officers and directors of our general partner, these individuals may become aware of business opportunities that may be appropriate for presentation to us as well as the other entities with which they are or may become affiliated. Due to

these existing and potential future affiliations and economic interests in these and other entities, they may have fiduciary obligations or incentives to present potential business opportunities to those entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present them to us. For further discussion of our management s business affiliations and the potential conflicts of interest of which our unitholders should be aware, please read Business and Properties Our Principal Business Relationships and Management.

Our partnership agreement limits our general partner s fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, which allows our general partner to consider only the interests and factors that it desires, without a duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, the exercise of its rights to transfer or vote the units it owns, the exercise of its registration rights and its determination whether or not to consent to any merger or consolidation involving us or to any amendment to the partnership agreement;

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith;

- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner acting in good faith and not involving a vote of unitholders must either be (i) on terms no less favorable to us than those generally being provided to or available from unrelated third parties or (ii) must be fair and reasonable to us, as determined by our general partner in good faith. In determining whether a transaction or resolution is fair and reasonable, our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us;

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter in question, our general partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal;

- provides that in resolving conflicts of interest, it will be presumed that in making its decision our general partner s board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and

- provides that in resolving conflicts of interest, it will be conclusively deemed that in making its decision the conflicts committee of our general partner s board of directors acted in good faith.

By purchasing a common unit, a unitholder will become bound by the provisions in the partnership agreement, including the provisions discussed above. Please read Fiduciary Duties.

Table of Contents

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval or with respect to which our general partner has sought conflicts committee approval, on such terms as it determines to be necessary or appropriate to conduct our business, including, but not limited to, the following:

- the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible or exchangeable into our securities, and the incurring of any other obligations;

- the purchase, sale or other acquisition or disposition of our securities, or the issuance of options, rights, warrants, restricted units, unit appreciation rights, phantom or tracking interests or other economic interests in us or relating to our securities;

- the acquisition, disposition, mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets or the merger or other combination of us with or into another entity (subject to certain prior approvals);

- the use of our assets (including cash on hand) for any purpose consistent with our partnership agreement;

- the negotiation, execution and performance of any contracts, conveyances or other instruments;

- the distribution of our cash;

- the selection, employment, retention and dismissal of employees and agents, outside attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;

- the maintenance of insurance for our benefit and the benefit of our partners;

- the formation of, or acquisition of an interest in, the contribution of property to, and the making of loans to, any limited or general partnerships, joint ventures, corporations, limited liability companies or other entities;

- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity and otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense and the settlement of claims and litigation;

- the indemnification of any person against liabilities and contingencies to the extent permitted by law;

- the making of tax, regulatory and other filings or rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets; and the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Our partnership agreement provides that our general partner must act in good faith when making decisions on our behalf, and our partnership agreement further provides that in order for a determination by our general partner to be made in good faith, our general partner must subjectively believe that the determination is in our best interests. Please read The Partnership Agreement Limited Voting Rights for information regarding matters that require unitholder approval.

Table of Contents

Our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership interests and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- the manner in which our business is operated;
- the amount, nature and timing of asset purchases and sales, including whether to pursue acquisitions that may also be suitable for affiliates of our general partner;
- the amount, nature and timing of our capital expenditures;
- the amount of borrowings;
- the issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

Our partnership agreement provides that we and our subsidiary may borrow funds from our general partner and its affiliates. However, our general partner and its affiliates may not borrow funds from us or our operating subsidiaries.

Our general partner determines which costs incurred by it are reimbursable by us.

We reimburse our general partner and its affiliates for costs incurred in managing and operating our business, including costs incurred in rendering staff and support services to us pursuant to the services agreement with our affiliate Mid-Con Energy Operating.

Payments for these services can be substantial and will reduce the amount of cash available for distribution to our unitholders. Please read Certain Relationships and Related Party Transactions Services Agreement. Our general partner has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate to us. In turn, our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. Please read Certain Relationships and Related Party Transactions.

In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, will not be the result of arm s-length negotiations.

Our partnership agreement allows our general partner to determine, in good faith, any amounts to pay itself or its affiliates for any services rendered to us. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither our partnership agreement nor any of the other agreements, contracts, and arrangements between us and our general partner and its affiliates are the result of arm s-length negotiations, and in the future some such agreement, contracts or arrangements may not be the result of arm s-length negotiations. Similarly, agreements, contracts or arrangements between us and our general partner and its affiliates that are entered into following the closing

Table of Contents

of this offering will not be required to be negotiated on an arm s-length basis, although, in some circumstances, our general partner may determine that the conflicts committee may make a determination on our behalf with respect to such arrangements.

Our general partner will determine, in good faith, the terms of any of these transactions entered into after the close of this offering.

Our general partner and its affiliates have no obligation to permit us to use any facilities or assets of our general partner and its affiliates, except as may be provided in contracts entered into specifically for such use. There is no obligation of our general partner and its affiliates to enter into any contracts of this kind.

Our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner may exercise its right to call and purchase common units as provided in the partnership agreement or assign this right to one of its affiliates or to us. Our general partner is not bound by fiduciary duty restrictions in determining whether to exercise this right. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please read The Partnership Agreement Limited Call Right.

Common unitholders will have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us, on the one hand, and our general partner and its affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Our general partner has limited its liability regarding our obligations.

Our general partner has and will enter into contractual arrangements on our behalf and has and will limit its liability under such contractual arrangements so that the other party has recourse only to our assets and not against our general partner or its assets. The partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

The attorneys, independent accountants and others who have performed services for us regarding this offering have been retained by our general partner. The attorneys, independent accountants and others who perform services for us are selected by our general partner, or the conflicts committee of our general partner s board of directors, and may also perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

Table of Contents

Fiduciary Duties

Our general partner is accountable to us and our unitholders as a fiduciary. Fiduciary duties owed to unitholders by our general partner are prescribed by law and the partnership agreement. The Delaware Revised Uniform Limited Partnership Act, which we refer to in this prospectus as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, modify, restrict or expand the fiduciary duties otherwise owed by a general partner to limited partners and the partnership.

Our partnership agreement contains various provisions modifying and restricting the fiduciary duties that might otherwise be owed by our general partner. We have adopted these restrictions to allow our general partner and its affiliates to engage in transactions with us that would otherwise be prohibited by state-law fiduciary duty standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. Without these modifications, our general partner s ability to make decisions involving conflicts of interest would be restricted, and engaging in such transactions could result in violations of our general partner s state-law fiduciary standards. We believe these modifications are appropriate and necessary because our general partner s board of directors has fiduciary duties to manage our general partner in a manner beneficial to its owners, as well as to our unitholders. The modifications to the fiduciary standards enable our general partner to take into consideration the interests of all parties involved in the proposed action, so long as the resolution is fair and reasonable to us. These modifications also enable our general partner to attract and retain experienced and capable directors. These modifications are detrimental to our common unitholders because they restrict the rights and remedies that would otherwise be available to our unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below, and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interest.

The following is a summary of the material restrictions of the fiduciary duties owed by our general partner to the limited partners:

State-law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present.
Rights and remedies of unitholders	The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. These legal actions include actions against a general partner for breach of fiduciary duty or the partnership agreement. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.

Table of Contents

Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues about compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in good faith and will not be subject to any other standard under applicable law. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any fiduciary obligation to us or the unitholders whatsoever. These standards reduce the obligations to which our general partner would otherwise be held.

In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for losses sustained or liabilities incurred as a result of any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter in question, our general partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct, or in the case of a criminal matter, acted with the knowledge that such conduct was unlawful.

Special Provisions Regarding Affiliated Transactions. Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest that are not approved by a vote of unitholders and that are not approved by the conflicts committee of the board of directors of our general partner must be:

- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

- fair and reasonable to us, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us).

If our general partner does not seek approval from the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the bullet points above, then it will be presumed that, in making its decision, the board of directors, which may include board members affected by the conflict of interest, acted in good

Table of Contents

faith, and in any proceeding brought by or on behalf of any limited partner or us challenging such approval, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. These standards reduce the obligations to which our general partner would otherwise be held.

By purchasing our common units, each common unitholder automatically agrees to be bound by the provisions in our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner to sign a partnership agreement does not render our partnership agreement unenforceable against that person.

Under our partnership agreement, we must indemnify our general partner and its officers, directors, managers and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that, in respect of the matter for which these persons are seeking indemnification, these persons acted in bad faith or engaged in fraud or willful misconduct. We must also provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act of 1933, in the opinion of the SEC, such indemnification is contrary to public policy and, therefore, unenforceable. Please read The Partnership Agreement Indemnification.

Table of Contents

PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions. The information presented in this section assumes that our general partner will continue to make capital contributions to us in order to maintain its approximate 2.0% general partner interest.

Distributions of Available Cash

General

Our partnership agreement requires that, within 45 days after the end of each quarter, we will distribute all of our available cash to unitholders of record on the applicable record date. We will distribute approximately 98.0% of our available cash to our common unitholders, pro rata, and approximately 2.0% to our general partner. Unlike many publicly traded limited partnerships, 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 or any of our loan agreements, security agreements, mortgages, debt instruments or other agreements or obligations; 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 the cash and cash equivalents on hand on the date of determination of available cash for the quarter.

Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors and the liquidator in the order of priority provided in our partnership agreement and by law. Thereafter, we will distribute any remaining proceeds to our unitholders and our general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in the partnership agreement. Upon our liquidation, we will allocate any net gain (or unrealized gain attributable to assets distributed in kind to our partners) in the following manner:

first, to our general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances; and

Table of Contents

second, approximately 98.0% to the common unitholders, pro rata, and approximately 2.0% to our general partner.

Manner of Adjustments for Losses

Upon our liquidation, we will generally allocate any loss to our general partner and the unitholders in the following manner:

- *first*, approximately 98.0% to the holders of common units, in proportion to the positive balances in their capital accounts and approximately 2.0% to our general partner, until the capital accounts of our unitholders have been reduced to zero; and

- *thereafter*, 100% to our general partner.

Adjustments to Capital Accounts

Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for U.S. federal income tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and our general partner in the same manner as we allocate gain or loss upon liquidation.

Table of Contents

DESCRIPTION OF THE COMMON UNITS

The Units

Our common units are traded on the NASDAQ Global Market under the symbol MCEP. At the close of business on October 11, 2012, based upon information received from our transfer agent and brokers and nominees, we had approximately 25 unrestricted common unitholders of record. This number does not include owners for whom common units may be held in street name or whose common units are restricted. The holders of units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the rights of holders of common units in and to partnership distributions, please read this section and Provisions of Our Partnership Agreement Relating to Cash Distributions. For a description of other rights and privileges of limited partners under our partnership agreement, including voting rights, please read The Partnership Agreement.

Transfer Agent and Registrar

Duties

Wells Fargo Shareowner Services serves as registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units, except the following, which must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates or to cover taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There is no charge to our unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their respective stockholders, directors, officers and employees against all claims and losses that may arise out of their actions for their activities in that capacity, except for any liability due to any gross negligence or willful misconduct of the indemnitee.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of our partnership agreement; and
- makes the consents, acknowledgments and waivers contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with this offering.

138

Table of Contents

Our general partner may request that a transferee of common units certify that such transferee is an Eligible Holder. As of the date of this prospectus, an 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 of the United States, including a municipality of the United States;
- 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.

For the avoidance of doubt, 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.

In addition to other rights acquired upon transfer, the transferor gives the transferee the right to be admitted to our partnership as a limited partner with respect to the transferred common units. A transferee will become a limited partner of our partnership for the transferred common units automatically upon the recording of the transfer on our books and records. Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder s rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and any transfers are subject to the laws governing transfers of securities.

Table of Contents

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. The form of our partnership agreement is included in this prospectus as Appendix A. We will provide prospective investors with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please read Provisions of Our Partnership Agreement Relating to Cash Distributions;
- with regard to the fiduciary duties of our general partner, please read Conflicts of Interest and Fiduciary Duties;
- with regard to the transfer of common units, please read Description of the Common Units Transfer Agent and Registrar Transfer of Common Units; and
- with regard to allocations of taxable income, taxable loss and other matters, please read Material Tax Consequences.

Organization and Duration

Our partnership was organized in July 2011 and will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose under our partnership agreement is to engage directly in, or enter into or form, hold and dispose of any corporation, partnership, joint venture, limited liability company or other arrangement to engage directly in, any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law and, in connection therewith, to exercise all of the rights and powers conferred upon us pursuant to the agreements relating to such business activity and do anything necessary or appropriate to the foregoing. However, our general partner may not cause us to engage in any business activity that it determines would be reasonably likely to cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our general partner has the ability to cause us and our subsidiary to engage in activities other than the ownership, acquisition, exploitation and development of oil and natural gas properties and the ownership, acquisition and operation of related assets, our general partner has no current plans to do so and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners. Our general partner is generally authorized to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Cash Distributions

Our partnership agreement specifies the manner in which we will make cash distributions to our unitholders and other partnership interests as well as to our general partner in respect of its general partner interest. For a description of these cash distribution provisions, please read Provisions of Our Partnership Agreement Relating to Cash Distributions.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described under Limited Liability.

Table of Contents

For a discussion of our general partner s right to contribute capital to maintain its approximate 2.0% general partner interest if we issue additional units, please read Issuance of Additional Interests.

Limited Voting Rights

The following is a summary of the unitholder vote required for each of the matters specified below.

Various matters require the approval of a unit majority, which means the approval of a majority of the outstanding common units.

In voting their common units, our general partner, and our general partner s affiliates (including the Founders) and Yorktown will have no fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or our limited partners.

Issuance of additional units	No approval right. Please read Issuance of Additional Interests.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of any limited partner. Other amendments generally require the approval of a unit majority. Please read Amendment of the Partnership Agreement.
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority, in certain circumstances. Please read Merger, Consolidation, Sale or Other Disposition of Assets.
Dissolution of our partnership	Unit majority. Please read Dissolution.
Continuation of our business upon dissolution	Unit majority. Please read Dissolution.
Withdrawal of our general partner	Prior to December 31, 2021, under most circumstances, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates (including the Founders), is required for the withdrawal of our general partner in a manner that would cause a dissolution of our partnership. Please read Withdrawal or Removal of Our General Partner.
Removal of our general partner	Not less than $66^2/_3$% of the outstanding units, including units held by our general partner and its affiliates (including the Founders). Please read Withdrawal or Removal of Our General Partner.
Transfer of our general partner interest	Our general partner may transfer without a vote of our unitholders all, but not less than all, of its general partner interest in us to an affiliate or another person (other than an individual) in connection with its merger or consolidation with or into, or sale of all, or substantially all, of its assets to, such other person. The approval of a majority of the common units, excluding common units held by our general partner and its affiliates (including the Founders), is required in other circumstances for a transfer of the general partner

Table of Contents

	interest to a third party prior to December 31, 2021. Please read Transfer of General Partner Interest.
Transfer of ownership interests in our general partner	No approval required at any time. Please read Transfer of Ownership Interests in Our General Partner.

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);

- brought in a derivative manner on our behalf;

- asserting a claim of breach of duty (including any fiduciary duty) owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;

- asserting a claim arising pursuant to or to interpret or enforce any provision of the Delaware Act; or

- asserting a claim governed by the internal affairs doctrine,

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court in the State of Delaware with subject matter jurisdiction), in each case, regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. By purchasing a common unit, a limited partner (i) irrevocably submits to the exclusive jurisdiction of such courts in connection with any such claim, suit, action or proceedings; (ii) irrevocably agrees not to, and waives any right to, assert in any such claim, suit, action or proceeding that (A) it is not personally subject to the jurisdiction of such courts or of any other court to which proceedings in such courts may be appealed, (B) such claim, suit, action or proceeding is brought in an inconvenient forum, or (C) the venue of such claim, suit, action or proceeding is improper; (iii) expressly waives any requirement for the posting of a bond by a party bringing such claim, suit, action or proceeding; (v) consents to process being served in any such claim, suit, action or proceeding by (X) mailing, certified mail, return receipt requested, a copy thereof to such party at the address in effect for notices under our partnership agreement or (Y) any other manner permitted by law; and (vi) irrevocably waives any and all right to trial by jury in any such claim, suit, action or proceeding.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of our partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. If it were determined, however, that the right or exercise of the right by our limited partners as a group:

- to remove or replace our general partner;

- to approve some amendments to the partnership agreement; or to take other action under the partnership agreement;

Table of Contents

constituted participation in the control of our business for the purposes of the Delaware Act, then our limited partners could be held personally liable for our obligations under Delaware law, to the same extent as our general partner. This liability would extend to persons who transact business with us and reasonably believe that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Our operating subsidiary conducts business in Oklahoma and Colorado, and we may have operating subsidiaries that conduct business in other states in the future. Maintenance of our limited liability as an owner of our operating subsidiary may require compliance with legal requirements in the jurisdictions in which our operating subsidiary conducts business, including qualifying our operating subsidiary to do business there.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership in our subsidiary or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by our limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the control of our business for purposes of the statutes of any relevant jurisdiction, then our limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of our limited partners.

Issuance of Additional Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests and options, rights, warrants, restricted units, appreciation rights, phantom or tracking interests or other economic interests in us or in our securities for the consideration and on the terms and conditions determined by our general partner without the approval of our unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiary of equity interests, which may effectively rank senior to our common units.

If we issue additional partnership interests (other than the issuance of partnership interests upon conversion of any outstanding partnership interests that may be converted into common units), our general partner is entitled, but not required, to make additional capital contributions to the extent necessary to maintain its approximate 2.0% general partner interest in us. Our general partner s approximate 2.0% general partner interest in us will be reduced if we complete any such issuance of partnership interests in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its approximate 2.0% general partner interest in us. Moreover, our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units or other partnership interests whenever, and on the same terms that, we issue those interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the aggregate percentage interest in us of our general partner and its affiliates, including such interest represented by common units or other partnership interests, that existed immediately prior to each issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership interests.

Amendment of the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith and in the best interests of us or our limited partners. To adopt a proposed amendment, other than the amendments discussed below under No Unitholder Approval, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of our limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or

- enlarge the obligations of, restrict, change or modify in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole discretion.

The provision of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units (including units owned by our general partner, our general partner s affiliates (including the Founders) and Yorktown) or upon receipt of a written opinion of counsel acceptable to our general partner to the effect that such amendment will not affect the limited liability of any limited partner under the Delaware Act.

Following this offering, affiliates of our general partner (including the Founders) and Yorktown will own an aggregate of approximately 36.0% of our outstanding common units, or approximately 32.8% of our outstanding common units if the underwriters exercise in full their option to purchase additional common units.

No Unitholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate for us to qualify or to continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that neither we, nor our subsidiary will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- a change in our fiscal year or taxable period and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or the directors, officers, agents or trustees of our general partner from in any manner being subjected to the provisions of the Investment Company Act of 1940, as amended, the Investment Advisers Act of 1940, as amended, or plan asset regulations adopted under the Employee Retirement Income Security Act of 1974, as amended, or ERISA, regardless of whether such are substantially similar to plan asset regulations currently applied or proposed by the U.S. Department of Labor;
- an amendment that our general partner determines to be necessary or appropriate for the creation, authorization or issuance of any class or series of additional partnership securities or options, rights, warrants, restricted units, appreciation rights, tracking or phantom interests or other economic interests in the partnership relating to our securities;
- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate to reflect and account for the formation by us of, or our investment in, any corporation, partnership, limited liability company, joint venture or other entity, as otherwise permitted by our partnership agreement;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance subject in each case to certain restrictions; or

any other amendments substantially similar to any of the matters described in the clauses above.

Table of Contents

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect our limited partners (or any particular class of limited partners) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of our units or to comply with any rule, regulation, guideline or requirement of any securities exchange on which any class of our partnership interests is or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval

Our general partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to our limited partners or result in our being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes in connection with any of the amendments described above under No Unitholder Approval. No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding units unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under Delaware law of any of our limited partners.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected, but no vote will be required by any class or classes or type or types of limited partners that our general partner determines are not adversely affected in any material respect. Any amendment that reduces the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of partners holding aggregate partnership interests constituting not less than the voting requirement sought to be reduced. Any amendment that would increase the percentage of units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be increased.

Merger, Consolidation, Sale or Other Disposition of Assets

A merger or consolidation of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger or consolidation and may decline to do so free of any duty (including any fiduciary duty) or obligation whatsoever to us or our limited partners, including any duty to act in good faith and in the best interest of us or our limited partners.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us, among other things, to sell, exchange or otherwise dispose of all or substantially all of our and our subsidiary s assets (taken as a whole) in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination or sale of ownership interests of our subsidiary. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without such approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without such approval. Finally, our general partner may consummate any merger or consolidation without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the merger or consolidation will not result in a material amendment to our partnership agreement (other than an amendment that the general partner could adopt without the consent of other partners), each of our partnership interests outstanding immediately prior to the merger or consolidation will be an identical partnership interest of our partnership following the transaction, and the number partnership interests to be issued in such merger or consolidation does not exceed 20% of our outstanding partnership interests immediately prior to the effective date of such merger or consolidation.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or our subsidiary into a new limited liability entity or merge us or our subsidiary into, or convey all of our assets to, a newly formed entity that has no assets, liabilities or operations at the time of such conversion, merger or conveyance, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters, and the governing instruments of the new entity provide our limited partners and our general partner with substantially the same rights and obligations as contained in our partnership agreement. The unitholders are not entitled to dissenters rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Dissolution

We will continue as a limited partnership until dissolved under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with the Delaware Act;
- the entry of a decree of judicial dissolution of our partnership pursuant to the provisions of the Delaware Act; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner, other than by reason of a transfer of its general partner interest in us in accordance with our partnership agreement, unless a successor general partner is elected and admitted pursuant to our partnership agreement.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the exercise of the right would not result in the loss of limited liability under the Delaware Act of any limited partner; and
- neither our partnership nor our subsidiary would be treated as an association taxable as a corporation or otherwise be taxable as an entity for U.S. federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Table of Contents

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in Provisions of Our Partnership Agreement Relating to Cash Distributions Distributions of Cash Upon Liquidation. The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to December 31, 2021 without obtaining the approval of the holders of at least a majority of our outstanding common units, excluding common units held by our general partner and its affiliates (including the Founders), and furnishing an opinion of counsel regarding limited liability and tax matters. On or after December 31, 2021, our general partner may withdraw as our general partner without first obtaining approval of any unitholder by giving at least 90 days written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw as our general partner without unitholder approval upon 90 days notice to our limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than our general partner and its affiliates (including the Founders). In addition, subject to the restrictions set forth in our partnership agreement, on or after December 31, 2021, our general partner may sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read Transfer of General Partner Interest.

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority may, prior to the effective date of such withdrawal, elect a successor to the withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters is not obtained, we will be dissolved, wound up and liquidated, unless within a specified period of time after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please read Dissolution.

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than $66\,^2/_3\%$ of our outstanding units, including units held by our general partner, our general partner s affiliates (including the Founders) and Yorktown, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of our outstanding common units, voting as a separate class. The ownership of more than $33^1/_3\%$ of our outstanding units by our general partner, our general partner s affiliates (including the Founders) and Yorktown would give them the practical ability to prevent our general partner s removal. Following this offering, affiliates of our general partner (including the Founders) and Yorktown will own an aggregate of approximately 36.0% of our outstanding common units, or approximately 32.8% of our outstanding common units if the underwriters exercise in full their option to purchase additional common units.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist our general partner will have the right to convert its general partner interest into common units or to receive cash in exchange for those interests based on the fair market value of the interests at the time.

Table of Contents

In the event of removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the departing general partner s general partner interest for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached within the period provided under our partnership agreement, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. If the departing general partner and the successor general partner cannot agree upon one independent investment banking firm or other independent expert, then an independent investment banking firm or other independent expert chosen by agreement of the independent investment banking firm or other independent expert selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner will become a limited partner and such general partner interest will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interest

Except for the transfer by our general partner of all, but not less than all, of its general partner interest to:

- an affiliate of our general partner (other than an individual); or

- another entity as part of the merger or consolidation of our general partner with or into another entity or the transfer by our general partner of all or substantially all of its assets to another entity,

our general partner may not transfer all or any part of its general partner interest to another person prior to December 31, 2021, without the approval of the holders of at least a majority of our outstanding common units, excluding common units held by our general partner and its affiliates (including the Founders). As a condition of this transfer, the transferee must agree to purchase all (or the appropriate portion thereof, if applicable) of the partnership or membership interests held by our general partner as the general partner or managing member, if any, of us or our subsidiary and must assume, among other things, the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement, and furnish an opinion of counsel regarding limited liability and tax matters.

Our general partner, our general partner s affiliates (including the Founders) and Yorktown may at any time transfer common units to one or more persons without unitholder approval.

Transfer of Ownership Interests in Our General Partner

At any time, the members of our general partner may sell or transfer all or part of their membership interests in our general partner to an affiliate or a third party without the approval of our unitholders.

149

Table of Contents

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner or otherwise change the management of our general partner. If any person or group other than our general partner, its affiliates (including the Founders) and Yorktown acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights with respect to all of such partnership interests. This loss of voting rights does not apply to any person or group that acquires partnership interests directly from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires partnership interests with the prior approval of the board of directors of our general partner.

If our general partner is removed without cause, our partnership agreement provides that, among other things, our general partner will have the right to convert its general partner interest into common units or receive cash in exchange for those interests.

Limited Call Right

If at any time our general partner and its affiliates (including the Founders) own more than 80% of our then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign and transfer in whole or in part to any of its affiliates or to us, to purchase all, but not less than all, of the limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days notice. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by our general partner or any of its affiliates for any limited partner interests of such class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase such limited partner interests; and

- the average of the daily closing prices of the limited partner interests of such class over the 20 trading days preceding the date three days before the date the notice is mailed.

As a result of our general partner s right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or price. The federal income tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market. Please read Material Tax Consequences Disposition of Units.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of partnership interests then outstanding, record holders of limited partner interests on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited. Units that are owned by non-citizens or other ineligible holders will be voted by our general partner and our general partner will cast the votes on those units in the same ratios as the votes of limited partners on other units are cast. Please read Non-Citizen Unitholders; Redemption for additional information concerning the citizenship, nationality, and related status requirements for owning our common units.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. If authorized by our general partner, any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if an approval in writing or by electronic transmission is signed or transmitted by holders of not less than the number of units

Table of Contents

necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read Issuance of Additional Interests. However, if at any time any person or group, other than our general partner and its affiliates (including the Founders) or a direct or subsequently approved transferee of our general partner or its affiliates and specifically approved by our general partner, acquires, in the aggregate, beneficial ownership of 20% or more of any class of partnership interests then outstanding, that person or group will lose voting rights with respect to all of such partnership interests and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes or, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Status as Limited Partner

Upon a transfer of any common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records and such limited partner becomes the record holder of the common units so transferred. Except as described under Limited Liability, the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Unitholders; Redemption

We may acquire interests in oil and natural gas leases on United States federal lands in the future. To comply with certain U.S. laws relating to the ownership of interests in oil and natural gas leases on federal lands, our general partner, acting on our behalf, may request any unitholder to furnish to the general partner within 30 days of the request a properly completed certificate certifying as to the unitholder s nationality, citizenship or other related status. If, following a request by our general partner, a unitholder fails to furnish such certification within the 30-day period or if the general partner determines, with the advice of counsel, that the unitholder s nationality, citizenship or other related status would create a substantial risk of cancellation or forfeiture of property in which the we have an interest, we will have the right to redeem the units held by such unitholder. Further, the units held by such unitholder will not be entitled to any voting rights. The redemption price will be paid in cash or delivery of a promissory note, as determined by our general partner. If our general partner chooses to redeem the units in cash, the redemption price will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption. If our general partner chooses to redeem the units with a promissory note, the promissory note will bear interest at the rate of 5% annually and be payable in three equal annual installments of principal and accrued interest, commencing one year after the redemption date.

Table of Contents

For the avoidance of doubt, 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.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events whether civil, criminal, administrative or investigative, and whether formal or informal and including appeals:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a director, officer, employee, agent, manager, managing member, partner, fiduciary or trustee of us, our subsidiary or any entity set forth in the preceding three bullet points;
- any person who is or was serving at the request of a general partner, any departing general partner, or any affiliate of us or our subsidiary, as a director, officer, employee, agent, manager, managing member, general partner, fiduciary or trustee of another person owing a fiduciary duty to us or our subsidiary;
- any person who controls our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our general partner will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance covering liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on behalf of us or our subsidiary and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and our other affiliates, including Mid-Con Energy Operating, may be reimbursed. These expenses include salary, bonus, incentive compensation, employment benefits, and other amounts paid to persons who perform services for us or on our behalf, and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine in good faith the expenses that are allocable to us.

Books and Reports

Our general partner is required to keep appropriate books and records of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis in accordance with GAAP. For financial reporting and tax purposes, our fiscal year end is December 31.

We will furnish or make available to record holders of common units, within 100 days after the close of each fiscal year, an annual report containing audited financial statements, including a balance sheet and statements of operations, partnership equity and cash flows and a report on those financial statements by our independent registered public accounting firm. Except for our fourth quarter, we will also furnish or make available within 50 days after the close of each quarter, a report containing unaudited financial statements and such other information as may be received by applicable law, regulation or NASDAQ Global Market rule, or as our general partner determines to be necessary or appropriate.

Our general partner will be deemed to have made a report available if it has either filed such report with the SEC and such report is publicly available or made such report available on any publicly available website maintained by us.

The tax information reasonably required for federal, state and local income tax reporting purposes will be furnished within 90 days of the close of the calendar year in which our taxable period ends.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, obtain:

- a current list of the name and last known address of each record holder;
- copies of our partnership agreement, our certificate of limited partnership and related amendments if such documents are not available on the SEC s website;
- true and full information regarding the status of our business and financial condition (provided that these requirements will be satisfied to the extent the limited partner is furnished our most recent annual report any subsequent quarterly or periodic reports required to be filed with the SEC pursuant to Section 13 of the Exchange Act); and
- any other information regarding our affairs as our general partner determines in its sole discretion is just and reasonable.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under our partnership agreement, our general partner and its affiliates (including the Founders) have the right to cause us to register for resale under the Securities Act and applicable state securities laws any common units or other partnership interests proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. In addition, our general partner and its affiliates (including the Founders) have the right to include such securities in a registration by us or any other unitholder, subject to customary exceptions. These registration rights continue for two years following the withdrawal or removal of our general partner and for so long as is required for the holder to sell all of the partnership interests with respect to which it has requested registration during such two-year period. In addition, we are restricted from granting any superior piggyback registration rights during this two-year period. We will pay all expenses incidental to the registration, excluding underwriting fees and discounts. In connection with any registration of this kind, we will indemnify the unitholders participating in the registration and their officers, directors and controlling persons from and against specified liabilities, including under the Securities Act or any applicable state securities laws. Please read Units Eligible for Future Sale.

Table of Contents

UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered hereby, the Founders and Yorktown will hold an aggregate of 6,816,660 common units, or an aggregate of 6,216,660 common units if the underwriters exercise in full their option to purchase additional common units. The sale of these units could have an adverse impact on the price of the common units or on any trading market that may develop.

The common units sold in this offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units owned by an affiliate of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1.0% of the total number of the securities outstanding; or
- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A unitholder who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned his common units for at least six months (provided we are in compliance with the current public information requirement) or one year (regardless of whether we are in compliance with the current public information requirement), would be entitled to sell his common units under Rule 144 without regard to the rule s public information requirements, volume limitations, manner of sale provisions and notice requirements.

Our partnership agreement does not restrict our ability to issue any partnership interests. Any issuance of additional common units or other equity interests would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, our common units then outstanding. Please read The Partnership Agreement Issuance of Additional Interests.

Under our partnership agreement, our general partner and its affiliates, including the Founders, have the right to cause us to register under the Securities Act and applicable state securities laws the offer and sale of any common units or other partnership interests that they hold, which we refer to as registerable securities. Subject to the terms and conditions of our partnership agreement, these registration rights allow our general partner and its affiliates or their assignees holding any registerable securities to require registration of such registerable securities and to include any such registerable securities in a registration by us of common units or other partnership interests, including common units or other partnership interests offered by us or by any unitholder. Our general partner and its affiliates will continue to have these registration rights for two years following the withdrawal or removal of our general partner. In connection with any registration of units held by our general partner or its affiliates, we will indemnify each unitholder participating in the registration and its officers, directors, and controlling persons from and against any liabilities under the Securities Act or any applicable state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts. Except as described below, our general partner and its affiliates may sell their common units or other partnership interests in private transactions at any time, subject to compliance with certain conditions and applicable laws.

We, our general partner and certain of its affiliates and the directors and executive officers of our general partner have agreed, subject to certain exceptions, not to sell any common units for a period of 60 days from the date of this prospectus. For a description of these lock-up provisions, please read Underwriting.

Table of Contents

MATERIAL TAX CONSEQUENCES

This section is a summary of the material U.S. federal income, state and local tax consequences that may be relevant to prospective unitholders and, unless otherwise noted in the following discussion, is the opinion of Andrews Kurth LLP insofar as it describes legal conclusions with respect to matters of U.S. federal income tax law. Such statements are based on the accuracy of the representations made by our general partner and us to Andrews Kurth LLP, and statements of fact do not represent opinions of Andrews Kurth LLP. To the extent this section discusses U.S. federal income taxes, that discussion is based upon current provisions of the Internal Revenue Code of 1986, as amended (the Internal Revenue Code), existing and proposed Treasury regulations promulgated thereunder (the Treasury Regulations), and current administrative rulings and court decisions, all of which are subject to change. Changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to us or we are references to Mid-Con Energy Partners, LP and our subsidiary.

This section does not address all U.S. federal, state and local tax matters that affect us or our unitholders. To the extent that this section relates to taxation by a state, local or other jurisdiction within the United States, such discussion is intended to provide only general information. We have not sought the opinion of legal counsel regarding U.S. state, local or other taxation and, thus, any portion of the following discussion relating to such taxes does not represent the opinion of Andrews Kurth LLP or any other legal counsel. Furthermore, this section focuses on unitholders who are individual citizens or residents of the United States, whose functional currency is the U.S. dollar and who hold common units as a capital asset (generally, property that is held as an investment). This section has only limited application to corporations, partnerships (and entities treated as partnerships for U.S. federal income tax purposes), estates, trusts, non-resident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, non-U.S. persons, individual retirement accounts, employee benefit plans, real estate investment trusts or mutual funds. Accordingly, we encourage each prospective unitholder to consult such unitholder s own tax advisor in analyzing the U.S. federal, state, local and non-U.S. tax consequences particular to that unitholder resulting from his ownership or disposition of his common units.

No ruling has been or will be requested from the Internal Revenue Service (the IRS) regarding any matter that affects us or our unitholders. Instead, we will rely on opinions and advice of Andrews Kurth LLP. Unlike a ruling, an opinion of counsel represents only that counsel s best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for our common units and the prices at which such common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner. Furthermore, our tax treatment, or the tax treatment of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

For the reasons described below, Andrews Kurth LLP has not rendered an opinion with respect to the following specific U.S. federal income tax issues: (1) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read Tax Consequences of Unit Ownership Treatment of Short Sales); (2) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read Disposition of Units Allocations Between Transferors and Transferees); and (3) whether our method for depreciating Section 743 adjustments is sustainable in certain cases (please read Tax Consequences of Unit Ownership Section 754 Election and Uniformity of Units).

Table of Contents

Taxation of Mid-Con Energy Partners, LP

Partnership Status

We will be treated as a partnership for U.S. federal income tax purposes and, therefore, generally will not be liable for U.S. federal income taxes. Instead, each of our unitholders will be required to take into account his respective share of our items of income, gain, loss and deduction in computing his U.S. federal income tax liability as if the unitholder had earned such income directly, even if no cash distributions are made to the unitholder. Distributions by us to a unitholder generally will not be taxable to the unitholder unless the amount of cash distributed to the unitholder exceeds the unitholder s tax basis in his common units.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the Qualifying Income Exception, exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of qualifying income. Qualifying income includes income and gains derived from exploration and production of certain natural resources, including oil, natural gas, and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than 5% of our current gross income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and our general partner, and a review of the applicable legal authorities, Andrews Kurth LLP is of the opinion that at least 90% of our current gross income constitutes qualifying income. The portion of our income that is qualifying income may change from time to time.

No ruling has been or will be sought from the IRS, and the IRS has made no determination as to our status or the status of our operating subsidiary for U.S. federal income tax purposes or whether our operations generate qualifying income under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Andrews Kurth LLP on such matters. It is the opinion of Andrews Kurth LLP that we will be classified as a partnership and our operating subsidiary will be disregarded as an entity separate from us for U.S. federal income tax purposes.

In rendering its opinion, Andrews Kurth LLP has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Andrews Kurth LLP has relied include, without limitation:

(a) neither we nor our operating subsidiary has elected or will elect to be treated as a corporation; and

(b) for each taxable year, including short taxable years occurring as a result of a constructive termination, more than 90% of our gross income has been and will be income that Andrews Kurth LLP has opined or will opine is qualifying income within the meaning of Section 7704(d) of the Internal Revenue Code.

We believe that these representations have been true in the past and expect that these representations will continue to be true in the future.

If we fail to meet the Qualifying Income Exception, unless such failure is determined by the IRS to be inadvertent and is cured within a reasonable time after discovery (in which case the IRS may also require us to make adjustments with respect to our unitholders or pay other amounts), we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we failed to meet the Qualifying Income Exception, in return for stock in that corporation and then distributed that stock to our unitholders in liquidation of their interests in us. This deemed contribution and liquidation should be tax-free to our unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for U.S. federal income tax purposes.

If we were taxed as a corporation for U.S. federal income tax purposes in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return, rather than being passed through to our unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as taxable dividend income, to the extent of our current and accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder s tax basis in our common units, or taxable capital gain, after the unitholder s tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder s cash flow and after-tax return and thus would likely result in a substantial reduction of the value of our common units.

The discussion below is based on Andrews Kurth LLP s opinion that we will be classified as a partnership for U.S. federal income tax purposes.

Tax Consequences of Unit Ownership

Limited Partner Status

Unitholders who are admitted as limited partners of Mid-Con Energy Partners, LP, as well as unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of common units, will be treated as partners of Mid-Con Energy Partners, LP for U.S. federal income tax purposes. A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for U.S. federal income tax purposes. Please read Treatment of Short Sales. Unitholders who are not treated as partners in us as described above are urged to consult their own tax advisors with respect to the tax consequences applicable to them under the circumstances.

The references to unitholders in the discussion that follows are to persons who are treated as partners in Mid-Con Energy Partners, LP for federal income tax purposes.

Flow-Through of Taxable Income

Subject to the discussion below under Entity-Level Collections of Unitholder Taxes, neither we nor our subsidiary will pay any U.S. federal income tax. For U.S. federal income tax purposes, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether we make cash distributions to such unitholder. Consequently, we may allocate income to a unitholder even if that unitholder has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for his taxable year or years ending with or within our taxable year. Our taxable year ends on December 31.

Treatment of Distributions

Distributions made by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his common units immediately before the distribution. Cash distributions made by us to a unitholder in an

Table of Contents

amount in excess of the unitholder s tax basis in his common units generally will be considered to be gain from the sale or exchange of those common units, taxable in accordance with the rules described under Disposition of Units below. Any reduction in a unitholder s share of our liabilities, including as a result of future issuances of additional common units, will be treated as a distribution of cash to that unitholder. To the extent that cash distributions made by us cause a unitholder s at risk amount to be less than zero at the end of any taxable year, that unitholder must recapture any losses deducted in previous years. Please read Limitations on Deductibility of Losses.

A decrease in a unitholder s percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. This deemed distribution may constitute a non-pro rata distribution. A non-pro rata distribution of money or property, including a deemed distribution, may result in ordinary income to a unitholder, regardless of that unitholder s tax basis in its common units, if the distribution reduces the unitholder s share of our unrealized receivables, including depreciation recapture, depletion recapture and/or substantially appreciated inventory items, both as defined in Section 751 of the Internal Revenue Code, and collectively, Section 751 Assets. To the extent of such reduction, a unitholder will be treated as having received his proportionate share of the Section 751 Assets and then having exchanged those assets with us in return for an allocable portion of the non-pro rata distribution made to such unitholder. This latter deemed exchange generally will result in the unitholder s realization of ordinary income in an amount equal to the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder s tax basis (generally zero) in the Section 751 Assets deemed relinquished in the exchange.

Ratio of Taxable Income to Distributions

We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through the record date for distributions for the period ending December 31, 2014, will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than 45% of the cash distributed with respect to that period. Thereafter, we anticipate that the ratio of allocable taxable income to cash distributions to the unitholders could substantially increase. These estimates are based upon the assumption that gross income from operations will approximate the amount required to make the initial quarterly distribution on all common units and other assumptions with respect to capital expenditures, cash flow, net working capital and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure our unitholders that these estimates will prove to be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units. For example, the ratio of allocable taxable income to cash distributions to a purchaser of common units in this offering will be greater, and perhaps substantially greater, than our estimate with respect to the period described above if:

- gross income from operations exceeds the amount required to pay distributions at the initial quarterly distribution rate on all common units, yet we only pay distributions at the initial quarterly distribution rate on all common units; or

- we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering.

Basis of Units

A unitholder s initial tax basis in his common units will be the amount he paid for those common units plus his share of our nonrecourse liabilities. That basis generally will be (i) increased by the unitholder s share of our income and by any increases in such unitholder s share of our nonrecourse liabilities, and (ii) decreased, but not below zero, by distributions to him, by his share of our losses, by depletion deductions taken by him to the extent such deductions do not exceed his proportionate share of the adjusted tax basis of the underlying properties, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have no share of our debt that is recourse to our general partner, but will have a share, generally, based on his share of our profits, of our nonrecourse liabilities. Please read Disposition of Units Recognition of Gain or Loss.

Limitations on Deductibility of Losses

The deduction by a unitholder of that unitholder s share of our losses will be limited to the lesser of (i) the tax basis such unitholder has in his common units, and (ii) in the case of an individual, estate, trust or corporate unitholder (if more than 50% of the corporate unitholder s stock is owned directly or indirectly by or for five or fewer individuals or some tax exempt organizations) to the amount for which the unitholder is considered to be at risk with respect to our activities. A unitholder subject to these limitations must recapture losses deducted in previous years to the extent that distributions cause the unitholder s at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction in a later year to the extent that the unitholder s tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at risk limitation in excess of that gain would no longer be utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of the unitholder s common units, excluding any portion of that basis attributable to the unitholder s share of our nonrecourse liabilities, reduced by (1) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or other similar arrangement and (2) any amount of money the unitholder borrows to acquire or hold his common units, if the lender of those borrowed funds owns an interest in us, is related to another unitholder or can look only to the common units for repayment. A unitholder s at risk amount will increase or decrease as the tax basis of the unitholder s common units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in the unitholder s share of our liabilities.

The at risk limitation applies on an activity-by-activity basis, and in the case of oil and natural gas properties, each property is treated as a separate activity. Thus, a taxpayer s interest in each oil or natural gas property is generally required to be treated separately so that a loss from any one property would be limited to the at risk amount for that property and not the at risk amount for all the taxpayer s oil and natural gas properties. It is uncertain how this rule is implemented in the case of multiple oil and natural gas properties owned by a single entity treated as a partnership for federal income tax purposes. However, for taxable years ending on or before the date on which further guidance is published, the IRS will permit aggregation of oil or natural gas properties we own in computing a unitholder s at risk limitation with respect to us. If a unitholder were required to compute his at risk amount separately with respect to each oil or natural gas property we own, he might not be allowed to utilize his share of losses or deductions attributable to a particular property even though he has a positive at risk amount with respect to his common units as a whole.

In addition to the basis and at risk limitations on the deductibility of losses, the passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations may deduct losses from passive activities, which are generally defined as trade or business activities in which the taxpayer does not materially participate, only to the extent of the taxpayer s income from those passive activities. The passive loss limitations are applied separately with respect to each publicly-traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or a unitholder s investments in other publicly-traded partnerships, or a unitholder s salary or active business income. Passive losses that are not deductible because they exceed a unitholder s share of passive income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive loss limitations are applied after other applicable limitations on deductions, including the at risk rules and the basis limitation.

A unitholder s share of our net passive income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

Limitations on Interest Deductions

The deductibility of a non-corporate taxpayer s investment interest expense is generally limited to the amount of that taxpayer s net investment income. Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder s investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment or (if applicable) qualified dividend income. The IRS has indicated that net passive income earned by a publicly-traded partnership will be treated as investment income to its unitholders for purposes of the investment interest expense limitation. In addition, the unitholder s share of our portfolio income will be treated as investment income.

Entity-Level Collections of Unitholder Taxes

If we are required or elect under applicable law to pay any U.S. federal, state, local or non-U.S. tax on behalf of any unitholder or our general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the unitholder on whose behalf the payment was made. If the payment is made on behalf of a unitholder whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of common units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual unitholder in which event the unitholder would be required to file a claim in order to obtain a credit or refund.

Table of Contents

Allocation of Income, Gain, Loss and Deduction

In general, our items of income, gain, loss and deduction will be allocated among our general partner and the unitholders in accordance with their percentage interests in us. If we have a net loss for an entire taxable year, the loss will be allocated first to our general partner and the unitholders in accordance with their percentage interests in us to the extent of the unitholders positive capital accounts as adjusted to take into account the unitholders share of nonrecourse debt, and thereafter to our general partner.

Specified items of our income, gain, loss and deduction will be allocated to account for the difference between the tax basis and fair market value of our assets, a Book Tax Disparity, at the time of this offering and any future offerings or certain other transactions. The effect of these allocations, referred to as Section 704(c) Allocations, to a unitholder acquiring common units in this offering will be essentially the same as if the tax bases of our assets were equal to their fair market values at the time of this offering. However, in connection with providing this benefit to any future unitholders, similar allocations will be made to all holders of partnership interests immediately prior to a future offering or certain other transactions, including purchasers of common units in this offering, to account for any Book Tax Disparity at the time of such transaction. In addition, items of recapture income will be allocated to the extent possible to the unitholder who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by other unitholders.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate a Book-Tax Disparity, will generally be given effect for U.S. federal income tax purposes in determining a unitholder s share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a unitholder s share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the partners in profits and losses;
- the interest of all the partners in cash flow; and
- the rights of all the partners to distributions of capital upon liquidation.

Andrews Kurth LLP is of the opinion that, with the exception of the issues described in Section 754 Election and Disposition of Common Units Allocations Between Transferors and Transferees, allocations under our partnership agreement will be given effect for federal income tax purposes in determining a partner s share of an item of income, gain, loss or deduction.

Treatment of Short Sales

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

- any of our income, gain, loss or deduction with respect to those common units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those common units would be fully taxable; and
- all of these distributions may be subject to tax as ordinary income.

Andrews Kurth LLP has not rendered an opinion regarding the tax treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of our common units. 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 with their tax advisor about modifying any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their common units. The IRS has previously announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please read Disposition of Units Recognition of Gain or Loss.

Alternative Minimum Tax

Each unitholder will be required to take into account the unitholder s distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for non-corporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective unitholders are urged to consult with their tax advisors with respect to the impact of an investment in our common units on their liability for the alternative minimum tax.

Tax Rates

Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 35% and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) of individuals is 15%. However, absent new legislation extending the current rates, beginning January 1, 2013, the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. These rates are subject to change by new legislation at any time.

A 3.8% Medicare tax on certain investment income earned by individuals, estates, and trusts will apply for taxable years beginning after December 31, 2012. For these purposes, investment income generally includes a unitholder s allocable share of our income and gain realized by a unitholder from a sale of common units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder s net investment income from all investments, or (ii) the amount by which the unitholder s modified adjusted gross income exceeds specified threshold levels depending on a unitholder s federal income tax filing status. In the case of an estate or trust, the tax will be imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

Section 754 Election

We have made the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. That election generally permits us to adjust a unit purchaser s tax basis in our assets (inside basis) under Section 743(b) of the Internal Revenue Code to reflect the unitholder s purchase price. The Section 743(b) adjustment separately applies to any transferee of a unitholder who purchases outstanding common units from another unitholder based upon the values and bases of our assets at the time of the transfer to the transferee. The Section 743(b) adjustment does not apply to a person who purchases common units directly from us, and belongs only to the purchaser and not to other unitholders. Please read, however, Allocation of Income, Gain, Loss and Deduction. For purposes of this discussion, a unitholder s inside basis in our assets will be considered to have two components: (1) the unitholder s share of our tax basis in our assets (common basis) and (2) the unitholder s Section 743(b) adjustment to that basis.

Table of Contents

The timing and calculation of deductions attributable to Section 743(b) adjustments to our common basis will depend upon a number of factors, including the nature of the assets to which the adjustment is allocable, the extent to which the adjustment offsets any Internal Revenue Code Section 704(c) type gain or loss with respect to an asset and certain elections we make as to the manner in which we apply Internal Revenue Code Section 704(c) principles with respect to an asset to which the adjustment is applicable. Please read Allocation of Income, Gain, Loss and Deduction.

The timing of these deductions may affect the uniformity of our common units. Under our partnership agreement, our general partner is authorized to take a position to preserve the uniformity of common units even if that position is not consistent with these and any other Treasury Regulations or if the position would result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read Uniformity of Units. Andrews Kurth LLP is unable to opine as to the validity of any such alternate tax positions because there is no clear applicable authority. A unitholder s basis in a unit is reduced by his share of our deductions (whether or not such deductions were claimed on an individual income tax return) so that any position that we take that understates deductions will overstate the unitholder s basis in his common units and may cause the unitholder to understate gain or overstate loss on any sale of such common units. Please read Uniformity of Units.

A Section 754 election is advantageous if the transferee s tax basis in his common units is higher than the common units share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation and depletion deductions and the transferee s share of any gain or loss on a sale of assets by us would be less. Conversely, a Section 754 election is disadvantageous if the transferee s tax basis in his common units is lower than those common units share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the common units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer, or if we distribute property and have a substantial basis reduction. Generally a built-in loss or a basis reduction is substantial if it exceeds $250,000.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the fair market value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment we allocated to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally either non-amortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure our unitholders that the determinations we make will not be successfully challenged by the IRS or that the resulting deductions will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should our general partner determine the expense of compliance exceeds the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of common units may be allocated more income than such purchaser would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his common

Table of Contents

units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than one year of our income, gain, loss and deduction. Please read Disposition of Units Allocations Between Transferors and Transferees.

Depletion Deductions

Subject to the limitations on deductibility of losses discussed above (please read Tax Consequences of Unit Ownership Limitations on Deductibility of Losses), unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to our oil and natural gas interests. Although the Internal Revenue Code requires each unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying property for depletion and other purposes, we intend to furnish each of our unitholders with information relating to this computation for federal income tax purposes. Each unitholder, however, remains responsible for calculating his own depletion allowance and maintaining records of his share of the adjusted tax basis of the underlying property for depletion and other purposes.

Percentage depletion is generally available with respect to unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Internal Revenue Code. To qualify as an independent producer eligible for percentage depletion (and that is not subject to the intangible drilling and development cost deduction limits, please read Deductions for Intangible Drilling and Development Costs), a unitholder, either directly or indirectly through certain related parties, may not be involved in the refining of more than 75,000 barrels of oil (or the equivalent amount of natural gas) on average for any day during the taxable year or in the retail marketing of oil and natural gas products exceeding $5.0 million per year in the aggregate. Percentage depletion is calculated as an amount generally equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the unitholder s gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable income of the unitholder from the property for each taxable year, computed without the depletion allowance. A unitholder that qualifies as an independent producer may deduct percentage depletion only to the extent the unitholder s average net daily production of domestic crude oil, or the natural gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil and natural gas production, with 6,000 cubic feet of domestic natural gas production regarded as equivalent to one barrel of crude oil. The 1,000-barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by such persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a unitholder s total taxable income from all sources for the year, computed without the depletion allowance, net operating loss carrybacks, or capital loss carrybacks. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for such year plus the deduction carryover does not exceed 65% of the unitholder s total taxable income for that year. The carryover period resulting from the 65% net income limitation is unlimited.

Unitholders that do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (i) dividing the unitholder s share of the adjusted tax basis in the underlying mineral property by the number of mineral common units (barrels of oil and thousand cubic feet, or Mcf, of natural gas) remaining as of the beginning of the taxable year and (ii) multiplying the result by the number of mineral common units sold within the

taxable year. The total amount of deductions based on cost depletion cannot exceed the unitholder s share of the total adjusted tax basis in the property.

All or a portion of any gain recognized by a unitholder as a result of either the disposition by us of some or all of our oil and natural gas interests or the disposition by the unitholder of some or all of his common units may be taxed as ordinary income to the extent of recapture of depletion deductions, except for percentage depletion deductions in excess of the tax basis of the property. The amount of the recapture is generally limited to the amount of gain recognized on the disposition.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and Treasury Regulations relating to the availability and calculation of depletion deductions by the unitholders. Further, because depletion is required to be computed separately by each unitholder and not by our partnership, no assurance can be given, and counsel is unable to express any opinion, with respect to the availability or extent of percentage depletion deductions to the unitholders for any taxable year. Moreover, the availability of percentage depletion may be reduced or eliminated if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read Recent Legislative Developments. We encourage each prospective unitholder to consult his tax advisor to determine whether percentage depletion would be available to him.

Deductions for Intangible Drilling and Development Costs

We have elected to currently deduct intangible drilling and development costs, or IDCs. IDCs generally include our expenses for wages, fuel, repairs, hauling, supplies and other items that are incidental to, and necessary for, the drilling and preparation of wells for the production of oil, natural gas, or geothermal energy. The option to currently deduct IDCs applies only to those items that do not have a salvage value.

Although we have elected to currently deduct IDCs, each unitholder will have the option of either currently deducting IDCs or capitalizing all or part of the IDCs and amortizing them on a straight-line basis over a 60-month period, beginning with the taxable month in which the expenditure is made. If a unitholder makes the election to amortize the IDCs over a 60-month period, no IDC preference amount in respect of those IDCs will result for alternative minimum tax purposes.

Integrated oil companies must capitalize 30% of all their IDCs (other than IDCs paid or incurred with respect to oil and natural gas wells located outside of the United States) and amortize these IDCs over 60 months beginning in the month in which those costs are paid or incurred. If the taxpayer ceases to be an integrated oil company, it must continue to amortize those costs as long as it continues to own the property to which the IDCs relate. An integrated oil company is a taxpayer that has economic interests in oil or natural gas properties and also carries on substantial retailing or refining operations. An oil or natural gas producer is deemed to be a substantial retailer or refiner if it is does not qualify as an independent producer under the rules disqualifying retailers and refiners from taking percentage depletion. Please read Depletion Deductions.

IDCs previously deducted that are allocable to property (directly or through ownership of an interest in a partnership) and that would have been included in the adjusted tax basis of the property had the IDC deduction not been taken are recaptured to the extent of any gain realized upon the disposition of the property or upon the disposition by a unitholder of interests in us. Recapture is generally determined at the unitholder level. Where only a portion of the recapture property is sold, any IDCs related to the entire property are recaptured to the extent of the gain realized on the portion of the property sold. In the case of a disposition of an undivided interest in a property, a proportionate amount of the IDCs with respect to the property is treated as allocable to the transferred undivided interest to the extent of any gain recognized. Please read Disposition of Units Recognition of Gain or Loss.

The election to currently deduct IDCs may be restricted or eliminated if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read Recent Legislative Developments.

Table of Contents

Deduction for U.S. Production Activities

Subject to the limitations on the deductibility of losses discussed above and the limitation discussed below, unitholders will be entitled to a deduction, herein referred to as the Section 199 deduction, equal to 9% of the lesser of (i) our qualified production activities income that is allocated to such unitholder or (ii) the common unitholder s taxable income.

A common unitholder s otherwise allowable Section 199 deduction for each taxable year is reduced by 3% of the least of (i) the oil related qualified production activities income of the taxpayer for the taxable year, (ii) the qualified production activities income of the taxpayer for the taxable year, or (iii) the taxpayer s taxable income for the taxable year (determined without regard to any Section 199 deduction). For this purpose, the term oil related qualified production activities income means the qualified production activities income attributable to the production, refining, processing, transportation, or distribution of oil, gas, or any primary production thereof. We expect that most of all of our qualified production activities income will consist of oil related qualified production activities income.

Qualified production activities income is generally equal to gross receipts from domestic production activities reduced by cost of goods sold allocable to those receipts, other expenses directly associated with those receipts, and a share of other deductions, expenses and losses that are not directly allocable to those receipts or another class of income. The products produced must be manufactured, produced, grown or extracted in whole or in significant part by the taxpayer in the United States.

For a partnership, the Section 199 deduction is determined at the partner level. To determine his Section 199 deduction, each unitholder will aggregate his share of the qualified production activities income allocated to him from us with the unitholder s qualified production activities income from other sources. Each unitholder must take into account his distributive share of the expenses allocated to him from our qualified production activities regardless of whether we otherwise have taxable income. However, our expenses that otherwise would be taken into account for purposes of computing the Section 199 deduction are taken into account only if and to the extent the unitholder s share of losses and deductions from all of our activities is not disallowed by the tax basis rules, the at risk rules or the passive activity loss rules. Please read Tax Consequences of Unit Ownership Limitations on Deductibility of Losses.

The amount of a unitholder s Section 199 deduction for each year is limited to 50% of the IRS Form W-2 wages actually or deemed paid by the unitholder during the calendar year that are deducted in arriving at qualified production activities income. Each unitholder is treated as having been allocated IRS Form W-2 wages from us equal to the unitholder s allocable share of our wages that are deducted in arriving at qualified production activities income for that taxable year. It is not anticipated that we or our operating subsidiary will pay material wages that will be allocated to our unitholders, and thus a unitholder s ability to claim the Section 199 deduction may be limited.

This discussion of the Section 199 deduction does not purport to be a complete analysis of the complex legislation and Treasury authority relating to the calculation of domestic production gross receipts, qualified production activities income, or IRS Form W-2 wages, or how such items are allocated by us to unitholders. Further, because the Section 199 deduction is required to be computed separately by each unitholder, no assurance can be given, and counsel is unable to express any opinion, as to the availability or extent of the Section 199 deduction to the unitholders. Moreover, the availability of Section 199 deductions may be reduced or eliminated if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read Recent Legislative Developments. Each prospective unitholder is encouraged to consult his tax advisor to determine whether the Section 199 deduction would be available to him.

Lease Acquisition Costs

The cost of acquiring oil and natural gas lease or similar property interests is a capital expenditure that must be recovered through depletion deductions if the lease is productive. If a lease is proved worthless and abandoned, the cost of acquisition less any depletion claimed may be deducted as an ordinary loss in the year the lease becomes worthless. Please read Tax Treatment of Operations Depletion Deductions.

Geophysical Costs

The cost of geophysical exploration incurred in connection with the exploration and development of oil and natural gas properties in the United States are deducted ratably over a 24-month period beginning on the date that such expense is paid or incurred. The amortization period for certain geological and geophysical expenditures may be extended if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read Recent Legislative Developments.

Operating and Administrative Costs

Amounts paid for operating a producing well are deductible as ordinary business expenses, as are administrative costs, to the extent they constitute ordinary and necessary business expenses that are reasonable in amount.

Tax Basis, Depreciation and Amortization

The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to an offering will be borne by our partners holding interests in us prior to such offering. Please read Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction.

To the extent allowable, we may elect to use the depreciation and cost recovery methods, including bonus depreciation to the extent applicable, that will result in the largest deductions being taken in the early years after assets subject to these allowances are placed in service. We may not be entitled to any amortization deductions with respect to certain goodwill properties conveyed to us or held by us at the time of any future offering. Please read Uniformity of Units. Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please read Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction and Disposition of Units Recognition of Gain or Loss.

The costs incurred in selling our common units (called syndication expenses) must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts we incur will be treated as syndication expenses.

Table of Contents

Valuation and Tax Basis of Our Properties

The federal income tax consequences of the ownership and disposition of common units will depend in part on our estimates of the relative fair market values and the initial tax bases of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deduction previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of common units equal to the difference between the unitholder s amount realized and the unitholder s tax basis for the common units sold. A unitholder s amount realized will equal the sum of the cash or the fair market value of other property he receives plus his share of our liabilities. Because the amount realized includes a unitholder s share of our liabilities, the gain recognized on the sale of common units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us that in the aggregate were in excess of the cumulative net taxable income allocated for a unit that decreased a unitholder s tax basis in that unit will, in effect, become taxable income if the unit is sold at a price greater than the unitholder s tax basis in the unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder on the sale or exchange of a unit held for more than one year will generally be taxable as long-term capital gain or loss. However, a portion of this gain or loss, which will likely be substantial, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture or other unrealized receivables or inventory items that we own. The term unrealized receivables includes potential recapture items, including depreciation, depletion, amortization or IDC recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized on the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of common units. Capital losses may offset capital gains and no more than $3,000 of ordinary income each year, in the case of individuals, and may only be used to offset capital gain in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an equitable apportionment method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner s tax basis in his entire interest in the partnership as the value of the interest sold bears to the value of the partner s entire interest in the partnership. Treasury Regulations under Section 1223 of the Internal Revenue Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling discussed above, a unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the Treasury Regulations, he may designate specific common units sold for purposes of determining the holding period of common units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of our common units. A unitholder considering the purchase of additional common units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an appreciated partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract;

in each case, with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees

In general, our taxable income or loss will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of common units owned by each of them as of the opening of the applicable exchange on the first business day of the month (the Allocation Date). However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring common units may be allocated income, gain, loss and deduction realized after the date of transfer.

Although simplifying conventions are contemplated by the Internal Revenue Code and most publicly-traded partnerships use similar simplifying conventions, the use of this method may not be permitted under existing Treasury Regulations. Recently, however, the Department of the Treasury and the IRS issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly-traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, although such tax items must be prorated on a daily basis. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. Existing publicly-traded partnerships are entitled to rely on those proposed Treasury Regulations; however, they are not binding on the IRS and are subject to change until the final Treasury Regulations are issued. Accordingly, Andrews Kurth LLP is unable to opine on the validity of this method of allocating income and deductions between transferee and transferor unitholders. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the unitholder s interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between transferee and transferor unitholders, as well as among unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury Regulations.

Table of Contents

A unitholder who disposes of common units prior to the record date set for a cash distribution for any quarter will be allocated items of our income, gain, loss and deductions attributable to the month of sale but will not be entitled to receive that cash distribution.

Notification Requirements

A unitholder who sells any of his common units is generally required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of common units who purchases common units from another unitholder is also generally required to notify us in writing of that purchase within 30 days after the purchase. Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a transfer of common units may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker who will satisfy such requirements.

Constructive Termination

We will be considered to have terminated our tax partnership for U.S. federal income tax purposes upon the sale or exchange of interests in us that, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of measuring whether the 50% threshold has been met, multiple sales of the same unit are counted only once. A constructive termination results in the closing of our taxable year for all unitholders. 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 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 constructive termination occurring on a date other than December 31 will result in us filing two tax returns (and unitholders could receive two Schedules K-1 if the relief discussed below is not available) for one fiscal year and the cost of the preparation of these returns will be borne by all unitholders. However, pursuant to an IRS relief procedure for publicly traded partnerships that have technically terminated, the IRS may allow, among other things, that we provide a single Schedule K-1 for the tax year in which a termination occurs. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Uniformity of Units

Because we cannot match transferors and transferees of common units and because of other reasons, we must maintain uniformity of the economic and tax characteristics of the common units to a purchaser of these common units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity could result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to apply to a material portion of our assets. Any non-uniformity could have a negative impact on the value of the common units. Please read Tax Consequences of Unit Ownership Section 754 Election.

Our partnership agreement permits our general partner to take positions in filing our tax returns that preserve the uniformity of our common units even under circumstances like those described above. These positions may include reducing for some unitholders the depreciation, amortization or loss deductions to which they would otherwise be entitled or reporting a slower amortization of Section 743(b) adjustments for some unitholders than that to which they would otherwise be entitled. Andrews Kurth LLP is unable to

Table of Contents

opine as to validity of such filing positions. A unitholder s basis in common units is reduced by his share of our deductions (whether or not such deductions were claimed on an individual income tax return) so that any position that we take that understates deductions will overstate the unitholder s basis in his common units, and may cause the unitholder to understate gain or overstate loss on any sale of such common units. Please read Disposition of Units Recognition of Gain or Loss and Tax Consequences of Unit Ownership Section 754 Election. The IRS may challenge one or more of any positions we take to preserve the uniformity of common units. If such a challenge were sustained, the uniformity of common units might be affected, and, under some circumstances, the gain from the sale of common units might be increased without the benefit of additional deductions.

Tax-Exempt Organizations and Other Investors

Ownership of common units by employee benefit plans, other tax-exempt organizations, non-resident aliens, non-U.S. corporations and other non-U.S. persons raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them. Prospective unitholders who are tax-exempt entities or non-U.S. persons should consult their tax advisor before investing in our common units.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to it.

Non-resident aliens and foreign corporations, trusts or estates that own common units will be considered to be engaged in business in the United States because of the ownership of common units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, distributions to non-U.S. unitholders are subject to withholding at the highest applicable effective tax rate. Each non-U.S. unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns common units will be treated as engaged in a United States trade or business, that corporation may be subject to the United States branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation s U.S. net equity, which is effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a qualified resident. In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

A foreign unitholder who sells or otherwise disposes of a unit will be subject to U.S. federal income tax on gain realized from the sale or disposition of that unit to the extent the gain is effectively connected with a U.S. trade or business of the foreign unitholder. Under a ruling published by the IRS, interpreting the scope of effectively connected income, a foreign unitholder would be considered to be engaged in a trade or business in the U.S. by virtue of the U.S. activities of the partnership, and part or all of that unitholder s gain would be effectively connected with that unitholder s indirect U.S. trade or business. Moreover, under the Foreign Investment in Real Property Tax Act, a foreign unitholder generally will be subject to U.S. federal income tax upon the sale or disposition of a unit if (i) he owned (directly or constructively

Table of Contents

applying certain attribution rules) more than 5% of our common units at any time during the five-year period ending on the date of such disposition and (ii) 50% or more of the fair market value of all of our assets consisted of U.S. real property interests at any time during the shorter of the period during which such unitholder held the common units or the 5-year period ending on the date of disposition. Currently, more than 50% of our assets consist of U.S. real property interests and we do not expect that to change in the foreseeable future. Therefore, foreign unitholders may be subject to federal income tax on gain from the sale or disposition of their common units.

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each taxable year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder s share of income, gain, loss and deduction. We cannot assure our unitholders that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither we, nor Andrews Kurth LLP can assure prospective unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the common units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year s tax liability, and possibly may result in an audit of his return. Any audit of a unitholder s return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of U.S. federal income tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the Tax Matters Partner for these purposes. Our partnership agreement designates our general partner as our Tax Matters Partner.

The Tax Matters Partner will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate in that action.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

(1) the name, address and taxpayer identification number of the beneficial owner and the nominee;

(2) a statement regarding whether the beneficial owner is:

(a) a person that is not a U.S. person;

(b) a non-U.S. government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

(c) a tax-exempt entity;

(3) the amount and description of common units held, acquired or transferred for the beneficial owner; and

(4) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on common units they acquire, hold or transfer for their own account. A penalty of $100 per failure, up to a maximum of $1,500,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the common units with the information furnished to us.

Accuracy-Related Penalties

An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for the underpayment of that portion and that the taxpayer acted in good faith regarding the underpayment of that portion.

For individuals, a substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000 ($10,000 for most corporations). The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

(1) for which there is, or was, substantial authority; or

(2) as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an understatement of income for which no substantial authority exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for this penalty. More stringent rules apply to tax shelters, which we do not believe includes us, or any of our investments, plans or arrangements.

A substantial valuation misstatement exists if (a) the value of any property, or the tax basis of any property, claimed on a tax return is 150% or more of the amount determined to be the correct amount of the valuation or tax basis, (b) the price for any property or services (or for the use of property) claimed on any such return with respect to any transaction between persons described in Internal Revenue Code Section 482 is 200% or more (or 50% or less) of the amount determined under Section 482 to be the correct amount of such price, or (c) the net Internal Revenue Code Section 482 transfer price adjustment for the taxable year exceeds the lesser of $5.0 million or 10% of the taxpayer s gross receipts. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for a corporation other than an S Corporation or a personal holding company). The penalty is increased to 40% in the event of a gross valuation misstatement. We do not anticipate making any valuation misstatements.

In addition, the 20% accuracy-related penalty also applies to any portion of an underpayment of tax that is attributable to transactions lacking economic substance. To the extent that such transactions are not disclosed, the penalty imposed is increased to 40%. Additionally, there is no reasonable cause defense to the imposition of this penalty to such transactions.

Reportable Transactions

If we were to engage in a reportable transaction, we (and possibly our unitholders and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a listed transaction or that it produces certain kinds of losses for partnerships, individuals, S corporations, and trusts in excess of $2.0 million in any single tax year, or $4.0 million in any combination of six successive tax years. Our participation in a reportable transaction could increase the likelihood that our federal income tax information return (and possibly our unitholders tax return) would be audited by the IRS. Please read Information Returns and Audit Procedures.

Moreover, if we were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, our unitholders may be subject to the following additional consequences:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described in Accuracy-Related Penalties;

- for those persons otherwise entitled to deduct interest on federal tax deficiencies, nondeductibility of interest on any resulting tax liability; and

- in the case of a listed transaction, an extended statute of limitations.

We do not expect to engage in any reportable transactions.

Recent Legislative Developments

President Obama s budget proposal for the Fiscal Year 2013 and other recently introduced legislation include proposals that would, among other things, eliminate or reduce certain key U.S. federal income tax preferences relating to oil and natural gas exploration and development. Changes proposed 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

Table of Contents

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 common units.

In addition, the Obama Administration is considering, and, in the last Congressional session, the U.S. House of Representatives passed legislation that would have provided for substantive changes to the definition of qualifying income and the treatment of certain types of income earned from profits interests in partnerships. It is possible that these legislative efforts could result in changes to the existing federal income tax laws that affect publicly traded partnerships. As previously proposed, we do not believe any such legislation would affect our tax treatment as a partnership. However, the proposed legislation could be modified in a way that could affect us. 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 common units.

State, Local and Other Tax Considerations

In addition to U.S. federal income taxes, unitholders will be subject to other taxes, including state and local income taxes, unincorporated business taxes, and estate, inheritance or intangibles taxes that may be imposed by the various jurisdictions in which we conduct business or own property or in which the unitholder is a resident. We currently conduct business or own property in Oklahoma and Colorado, each of which imposes personal income taxes on individuals. These states also impose an income tax on corporations and other entities. Moreover, we may also own property or do business in other states in the future that impose income or similar taxes on nonresident individuals. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. A unitholder may be required to file state income tax returns and to pay state income taxes in any state in which we do business or own property, and such unitholder may be subject to penalties for failure to comply with those requirements. In some states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent taxable years. Some of the states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholder s income tax liability to the state, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please read Tax Consequences of Unit Ownership Entity-Level Collections of Unitholder Taxes. Based on current law and our estimate of our future operations, we anticipate that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, of his investment in us. Accordingly, each prospective unitholder is urged to consult, and depend on, his own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all tax returns that may be required of him. Andrews Kurth LLP has not rendered an opinion on the state, local or non-U.S. tax consequences of an investment in us.

Table of Contents

INVESTMENT IN MID-CON ENERGY PARTNERS, LP BY

EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and the restrictions imposed by Section 4975 of the Internal Revenue Code and provisions under any federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of the Internal Revenue Code or ERISA (collectively, Similar Laws). For these purposes the term employee benefit plan includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or individual retirement accounts or annuities, or IRAs, established or maintained by an employer or employee organization, and entities whose underlying assets are considered to include plan assets of such plans, accounts and arrangements (collectively, Employee Benefit Plans). Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA and any other applicable Similar Laws;

- whether in making the investment, the plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws;

- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return. Please read Material Tax Consequences Tax-Exempt Organizations and Other Investors; and

- whether making such an investment will comply with the delegation of control and prohibited transaction provisions of ERISA, the Internal Revenue Code and any other applicable Similar Laws.

The person with investment discretion with respect to the assets of an Employee Benefit Plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit Employee Benefit Plans, and IRAs that are not considered part of an Employee Benefit Plan, from engaging, either directly or indirectly, in specified transactions involving plan assets with parties that, with respect to the plan, are parties in interest under ERISA or disqualified persons under the Internal Revenue Code unless an exemption is available. A party in interest or disqualified person who engages in a non-exempt prohibited transaction may be subject to excise taxes and other penalties and liabilities under ERISA and the Internal Revenue Code. In addition, the fiduciary of the ERISA plan that engaged in such a non-exempt prohibited transaction may be subject to penalties and liabilities under ERISA and the Internal Revenue Code.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our general partner would also be a fiduciary of such plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code, ERISA and any other applicable Similar Laws.

The Department of Labor regulations and Section 3(42) of ERISA provide guidance with respect to whether, in certain circumstances, the assets of an entity in which Employee Benefit Plans acquire equity interests would be deemed plan assets. Under these rules, an entity s assets would not be considered to be plan assets if, among other things:

- the equity interests acquired by the Employee Benefit Plan are publicly offered securities i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, are freely transferable and are registered under certain provisions of the federal securities laws;

176

Table of Contents

- the entity is an operating company, i.e., it is primarily engaged in the production or sale of a product or service, other than the investment of capital, either directly or through a majority-owned subsidiary or subsidiaries; or

- there is no significant investment by benefit plan investors, which is generally defined to mean that less than 25% of the value of each class of equity interest, disregarding any such interests held by our general partner, its affiliates and certain persons, is held by the Employee Benefit Plans.

Our assets should not be considered plan assets under these regulations because it is expected that the investment will satisfy the requirements in the first two bullet points above.

In light of the serious penalties imposed on persons who engage in prohibited transactions or other violations, plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA, the Internal Revenue Code and other Similar Laws.

Table of Contents

UNDERWRITING

RBC Capital Markets, LLC, Raymond James & Associates, Inc., UBS Securities LLC and Wells Fargo Securities, LLC are acting as joint book-running managers of the offering and as representatives of the underwriters named below. Subject to the terms and conditions stated in the underwriting agreement dated the date of this prospectus, the underwriters set forth below have agreed to purchase from us and the Selling Unitholders the number of common units set forth opposite its name.

Underwriter	Number of Common Units
RBC Capital Markets, LLC	1,000,000
Raymond James & Associates, Inc.	800,000
UBS Securities LLC	800,000
Wells Fargo Securities, LLC	800,000
Robert W. Baird & Co. Incorporated	250,000
Oppenheimer & Co. Inc.	250,000
Stephens Inc.	100,000
Total	4,000,000

The underwriting agreement provides that the underwriters obligations to purchase the common units depend on the satisfaction of the conditions contained in the underwriting agreement and that if any of our common units are purchased by the underwriters, all of such common units must be purchased. The conditions contained in the underwriting agreement include the condition that all the representations and warranties made by us and the Selling Unitholders to the underwriters are true, that there has been no material adverse change in the condition of us or in the financial markets and that we deliver to the underwriters customary closing documents.

The following table shows the underwriting fees to be paid to the underwriters by us and the Selling Unitholders in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional common units. This underwriting fee is the difference between the initial price to the public and the amount the underwriters pay to us and the Selling Unitholders to purchase the common units. On a per common unit basis, the underwriting fee is 4.0% of the initial price to the public.

	Paid by Us	
	No Exercise	Full Exercise
Per common unit		
Public offering price	$ 21.20	$ 21.20
Discounts	$ 0.848	$ 0.848
Proceeds to us	$ 20.352	$ 20.352
Proceeds to Selling Unitholders	$ 20.352	$ 20.352
Total	$ 3,392,000	$ 3,900,800

We estimate that total expenses of the offering, other than underwriting discounts, will be approximately $524,104 split pro rata between us and the Selling Unitholders.

We and the Selling Unitholders have been advised by the underwriters that the underwriters propose to offer our common units directly to the public at the initial price to the public set forth on the cover page of this prospectus and to dealers (who may include the underwriters) at this price to the public less a concession not in excess of $0.51 per common unit. After the offering, the underwriters may change the offering price and other selling terms.

Table of Contents

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act or to contribute to payments that may be required to be made with respect to these liabilities.

The Selling Unitholders have granted to the underwriters an option to purchase up to an aggregate of 600,000 additional common units at the public offering price to the public less the underwriting discount set forth on the cover page of this prospectus, if any. Such option may be exercised in whole or in part at any time until 30 days after the date of this prospectus. If this option is exercised, each underwriter will be committed, subject to satisfaction of the conditions specified in the underwriting agreement, to purchase a number of additional common units proportionate to the underwriter s initial commitment as indicated in the preceding table, and the Selling Unitholders will be obligated, pursuant to the option, to sell these common units to the underwriters.

We, our general partner and certain of its affiliates, including the directors and executive officers of our general partner have agreed that we will not, directly or indirectly, offer, sell, short sell, contract to sell, pledge or otherwise dispose of any common units or securities convertible into or exchangeable or exercisable for common units, or enter into any derivative transaction with similar effect, for a period of 60 days after the date of this prospectus without the prior written consent of RBC Capital Markets, LLC. The restrictions described in this paragraph do not apply to:

- the sale of common units to the underwriters;
- restricted common units issued by us under the long-term incentive program or upon the exercise of options issued under the long-term incentive program; or
- certain transfers to affiliates and certain bona fide gifts.

The 60-day restricted period described in the preceding paragraphs will be extended if:

- during the last 17 days of the 60-day restricted period we issue an earnings release or material news or a material event relating to us occurs; or
- prior to the expiration of the 60-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 60-day period;

in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

RBC Capital Markets, LLC, in its sole discretion, may release the common units subject to lock-up agreements in whole or in part at any time with or without notice. When determining whether or not to release common units from lock-up agreements, RBC Capital Markets, LLC will consider, among other factors, the unitholders reasons for requesting the release, the number of common units for which the release is being requested and market conditions at the time. However, RBC Capital Markets, LLC has informed us that, as of the date of this prospectus, there are no agreements between them and any party that would allow such party to transfer any common units, nor do they have any intention at this time of releasing any of the common units subject to the lock-up agreements, prior to the expiration of the lock-up period.

Our partnership agreement requires that all common unitholders be Eligible Holders. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in oil and gas leases on federal lands. As of the date hereof, Eligible Holder means: (1) a citizen of the United States; (2) a corporation organized under the laws of the United States or of any state thereof; (3) a public body, including a municipality; (4) 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

Table of Contents

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 (5) 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. For the avoidance of doubt, 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.

In connection with this offering, the underwriters may engage in stabilizing transactions, short sales, syndicate covering transactions and penalty bids in accordance with Regulation M under the Securities Exchange Act of 1934.

Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

Short sales involve sales by the underwriters of the common units in excess of the number of common units the underwriters are obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the number of common units over-allotted by the underwriters is not greater than the number of common units they may purchase in their option to purchase additional common units. In a naked short position, the number of common units involved is greater than the number of common units in the underwriters option to purchase additional common units. The underwriters may close out any short position by either exercising their option and/or purchasing common units in the open market.

Syndicate covering transactions involve purchases of the common units in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the source of the common units to close out the short position, the underwriters will consider, among other things, the price of common units available for purchase in the open market as compared to the price at which they may purchase common units through their option. If the underwriters sell more common units than could be covered by their option to purchase additional common units, which we refer to in this prospectus as a naked short position, the position can only be closed out by buying common units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in the offering.

Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common units originally sold by the syndicate member are purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

Similar to other purchase transactions, the underwriters purchases to cover the syndicate short sales may have the effect of raising or maintaining the market price of the common units or preventing or retarding a decline in the market price of the common units. As a result, the price of the common units may be higher than the price that might otherwise exist in the open market.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common units or preventing or retarding a decline in the market price of the common units. As a result, the price of the common units may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the NASDAQ Global Market or otherwise and, if commenced, may be discontinued at any time.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common units. In

Table of Contents

addition, neither we nor any of the underwriters make any representation that the underwriters will engage in these stabilizing transactions or that any transaction, if commenced, will not be discontinued without notice.

Our common units are listed on the NASDAQ Global Market under the symbol MCEP.

The underwriters may, from time to time, engage in transactions with and perform services for us in the ordinary course of their business for which they may receive customary fees and reimbursement of expenses. Affiliates of RBC Capital Markets, LLC and Wells Fargo Securities, LLC are lenders under our credit facility and, accordingly, will receive a substantial portion of the net proceeds from this offering. In addition, certain affiliates of the underwriters have also served additional roles under that facility, such as administrative agent, for which they have received customary fees and reimbursement of expenses. Additionally, affiliates of certain of the underwriters are counterparties to certain of our hedging transactions. Pursuant to our credit agreement, we have agreed to indemnify the lenders and agents under that agreement against a variety of liabilities and to reimburse certain expenses. Also, an affiliate of Wells Fargo Securities, LLC will serve as the transfer agent and registrar for the common units.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their affiliates have provided, and may in the future provide, various investment banking, commercial banking, financial advisory and other financial services to us and our affiliates for which they have received, and may in the future receive, customary fees. Additionally, certain of the underwriters and their affiliates have engaged, and may from time to time in the future engage, in transactions with us in the ordinary course of their business.

In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments, including serving as counterparties to certain derivative and hedging arrangements, and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of us. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Because the Financial Industry Regulatory Authority views our common units as interests in a direct participation program, this offering is being made in compliance with Rule 2310 of the FINRA rules. Investor suitability with respect to the common units will be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

No sales to accounts over which any underwriter exercises discretionary authority in excess of 5% of the units offered by them may be made without the prior written approval of the customer.

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of common units for sale to online brokerage account holders. Any such allocation for online distributions will be made by the underwriters on the same basis as other allocations.

Table of Contents

Other than the prospectus in electronic format, information contained in any other web site maintained by an underwriter or selling group member is not part of this prospectus or the registration statement of which this prospectus forms a part, has not been endorsed by us and should not be relied on by investors in deciding whether to purchase any units. The underwriters and selling group members are not responsible for information contained in web sites that they do not maintain.

VALIDITY OF THE COMMON UNITS

The validity of the common units will be passed upon for us by Gable & Gotwals, A Professional Corporation, Tulsa, Oklahoma. Certain tax matters will be passed upon for us by Andrews Kurth LLP, Houston, Texas. Certain legal matters in connection with the common units offered by us will be passed upon for the underwriters by Latham & Watkins LLP, Houston, Texas.

EXPERTS

The audited consolidated financial statements of Mid-Con Energy Partners, LP and subsidiaries as of December 31, 2011 and 2010, and for the years ended December 31, 2011 and 2010, and for the period from inception (July 1, 2009) to December 31, 2009, included in this prospectus and elsewhere in the registration statement have been so included in reliance on the report of Grant Thornton LLP, independent registered public accountants, upon the authority of said firm as experts in auditing and accounting in giving said report.

The audited consolidated financial statements of Mid-Con Energy Corporation and subsidiaries for the year ended June 30, 2009, included in this prospectus and elsewhere in the registration statement have been so included in reliance upon the report of Grant Thornton LLP, independent registered public accountants, upon the authority of said firm as experts in auditing and accounting in giving said report.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-l regarding our common units. This prospectus, which constitutes part of the registration statement, does not contain all of the information set forth in the registration statement. For further information regarding us and our common units offered in this prospectus, we refer you to the full registration statement, including its exhibits and schedules, filed under the Securities Act. The full registration statement, of which this prospectus forms a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Copies of these materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at 100 F Street, NE, Room 1580, Washington, D.C. 20549. The registration statement, of which this prospectus forms a part, can also be downloaded from the SEC s web site on the Internet at *http://www.sec.gov.* You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330.

We furnish or make available to our unitholders annual reports containing our audited financial statements and furnish or make available quarterly reports containing our unaudited interim financial information, including the information required by Form 10-Q, for the first three fiscal quarters of each of our fiscal years. Additionally, we file other periodic reports with the SEC, as required by the Securities Exchange Act of 1934.

Table of Contents

FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements that 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.

These types of statements, other than statements of historical fact included in this prospectus, are forward-looking statements. These forward-looking statements may be found in Prospectus Summary, Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business and Properties and other sections of this prospectus. In some cases, you can identify forward-looking statements by terminology such as may, will, could, should, expect, plan, project, intend, anticipate, believe, estimate, pr target, continue, goal, forecast, guidance, continue, might, scheduled, and the negative of such terms or other comparable terminolo

Table of Contents

The forward-looking statements contained in this prospectus 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 prospectus are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in Risk Factors and elsewhere in this prospectus. All forward-looking statements speak only as of the date of this prospectus. 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.

Table of Contents

INDEX TO FINANCIAL STATEMENTS

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Balance Sheets

(in thousands, except number of units)

	June 30, 2012	December 31, 2011
	(unaudited)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,964	$ 228
Accounts receivable:		
Oil and gas sales	3,998	5,018
Other receivables	824	2,405
Derivative financial instruments	6,941	1,028
Prepaids and other	152	25
Total current assets	15,879	8,704
PROPERTY AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method:		
Proved properties	119,567	97,269
Accumulated depletion, depreciation and amortization	(16,112)	(11,403)
Total property and equipment, net	103,455	85,866
DERIVATIVE FINANCIAL INSTRUMENTS	5,332	1,505
OTHER ASSETS	482	536
Total assets	$ 125,148	$ 96,611
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 3,996	$ 4,575
Accrued liabilities	4	138
Other payables		1,630
Total current liabilities	4,000	6,343
LONG-TERM DEBT	58,000	45,000
ASSET RETIREMENT OBLIGATIONS	2,675	1,919
EQUITY, per accompanying statements:		
Partnership equity		
General partner interest	1,638	1,299
Limited partners- 17,789,561 units and 17,640,000 units issued and outstanding as of June 30, 2012 and December 31, 2011, respectively	58,835	42,050
Total equity	60,473	43,349

Total liabilities and equity	$ 125,148	$ 96,611

See accompanying notes to consolidated financial statements

F-1

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

Consolidated Statements of Operations

(in thousands, except per unit data)

	Six Months Ended June 30, 2012 (Unaudited)	Six Months Ended June 30, 2011 (Unaudited)
Revenues:		
Oil sales	$ 28,998	$ 15,609
Natural gas sales	353	658
Realized gain (loss) on derivatives, net	769	(715)
Unrealized gain on derivatives, net	9,741	1,046
Total Revenues	39,861	16,598
Operating costs and expenses:		
Lease operating expenses	4,725	3,550
Oil and gas production taxes	713	656
Dry holes and abandonments of unproved properties		772
Depreciation, depletion and amortization	4,709	2,418
Accretion of discount on asset retirement obligations	57	32
General and administrative	4,869	534
Total operating costs and expenses	15,073	7,962
Income from operations	24,788	8,636
Other income (expense):		
Interest income and other	5	62
Interest expense	(703)	(237)
Gain on sale of assets		1,209
Other revenue and expenses, net		576
Total other income (expense)	(698)	1,610
Net income	$ 24,090	$ 10,246
Computation of net income per limited partner unit:		
General partners interest in net income	$ 477	$ 203
Limited partners interest in net income	$ 23,613	$ 10,043
Net income per limited partner unit (basic and diluted)	$ 1.33	$ 0.57
Weighted average limited partner units outstanding:		
(basic and diluted)	17,790	17,640

See accompanying notes to consolidated financial statements

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

Consolidated Statements of Cash Flows

(in thousands)

	Six Months Ended June 30, 2012	2011
	(Unaudited)	
Cash Flows from Operating Activities:		
Net income	$ 24,090	$ 10,246
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	4,709	2,418
Debt placement fee amortization	54	
Accretion of discount on asset retirement obligations	57	32
Dry holes and abandonments of unproved properties		772
Unrealized gain on derivative instruments, net	(9,741)	(1,046)
Gain on sale of assets		(1,209)
Equity-based compensation	2,690	
Changes in operating assets and liabilities:		
Accounts receivable	1,020	(2,162)
Other receivable	(824)	
Other current assets	2,277	(48)
Accounts payable and accrued liabilities	52	(3,733)
Revenues payable		42
Advance billings and other		(120)
Net cash provided by operating activities	24,384	5,192
Cash Flows from Investing Activities:		
Additions to oil and gas properties	(7,566)	(11,825)
Additions to other property and equipment		(679)
Acquisitions of oil and natural gas properties	(16,426)	(8,161)
Proceeds from sale of other property and equipment		1,219
Proceeds from sale of investment in subsidiary, net of cash sold		2,095
Proceeds from sale of property and equipment to subsidiary, net of cash sold		4,000
Net cash used in investing activities	(23,992)	(13,351)
Cash Flows from Financing Activities:		
Proceeds from line of credit	16,000	15,950
Payments on line of credit	(3,000)	(7,900)
Borrowings on note payable		412
Payments on note payable		(84)
Distributions paid	(9,656)	
Repurchase of common units		(1)
Net cash provided by financing activities	3,344	8,377
Net increase in cash and cash equivalents	3,736	218
Beginning cash and cash equivalents	228	222

Ending cash and cash equivalents	$	3,964	$	440
Supplemental Cash Flow Information:				
Cash paid for interest	$	673	$	189
Non-Cash Investing and Financing Activities:				
Accrued capital expenditures oil and gas properties	$	932	$	310
Notes receivable from officers, directors and employees	$		$	58
Deferred gain on sale of property and equipment to subsidiary	$		$	2,766

See accompanying notes to consolidated financial statements

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

Consolidated Statements of Changes in Equity

(in thousands)

	General Partner	Limited Partner Units	Limited Partner Amount	Total Equity
		(Unaudited)		
Balance, December 31, 2011	$ 1,299	17,640	$ 42,050	$ 43,349
Distributions	(191)		(9,465)	(9,656)
Equity-based compensation	53	150	2,637	2,690
Net income	477		23,613	24,090
Balance, June 30, 2012	$ 1,638	17,790	$ 58,835	$ 60,473

See accompanying notes to consolidated financial statements.

Table of Contents

Mid-Con Energy Partners, LP

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Operations

Nature of Operations

Mid-Con Energy Partners, LP (we, our, or us) is a publicly held Delaware limited partnership 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 December 2011, Mid-Con Energy I, LLC and Mid-Con Energy II, LLC (together, our predecessor), merged into our wholly owned subsidiary, Mid-Con Energy Properties, LLC.

Basis of Presentation

Our unaudited condensed consolidated financial statements included herein have been prepared pursuant to the rules and regulations of the SEC. Accordingly, certain information and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) have been condensed or omitted. We believe that the presentations and disclosures herein are adequate to make the information not misleading. The unaudited condensed consolidated financial statements reflect all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the interim periods. The results of operations for the interim periods are not necessarily indicative of the results of operations to be expected for the full year. These interim financial statements should be read in conjunction with our Annual Report for the year ended December 31, 2011.

All intercompany accounts and transactions have been eliminated in consolidation. In the Notes to Unaudited Condensed Consolidated Financial Statements, all dollar and unit amounts in tabulations are in thousands of dollars and units, respectively, unless otherwise indicated.

Note 2. 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 combined purchase prices for these properties have been reflected in the unaudited condensed consolidated financial statements. We paid approximately $16.4 million in aggregate consideration for these properties. The transactions were financed using existing cash and proceeds from our credit facility.

Note 3. Equity Awards

We have a long-term incentive program (the Plan) 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 Plan 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. As of June 30, 2012, the Plan 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.

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

Table of Contents

Mid-Con Energy Partners, LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

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. The RUs are subject to forfeiture and we assume a 10% forfeiture rate for the RUs to estimate our equity-based compensation expense. These costs are reported as a component of general and administrative expense in our unaudited condensed consolidated statements of operations. The equity-based compensation expense for the six months ended June 30, 2012 was $2.7 million. There was no equity-based compensation expense for the six months ended June 30, 2011.

Note 4. 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.

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 as Unrealized gains on derivatives, net in our unaudited condensed consolidated statements 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.

As of June 30, 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
Swaps July 2012 through December 2012	$ 101.85			222,000
Collars July 2012 through December 2012		$ 100.00	$ 117.00	36,000
Swaps 2013	$ 100.30			408,000
Collars 2013		$ 100.00	$ 111.00	72,000
Swaps 2014	$ 97.87			240,000

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

		Asset Derivatives		Liability Derivatives	
		June 30, 2012	December 31, 2011	June 30, 2012	December 31, 2011
Derivative financial instruments	current asset	$ 6,941	$ 1,028	$	$
Derivative financial instruments	long term asset	5,332	1,505		
Derivative financial instruments	current liability				
Derivative financial instruments	long term liability				
		$ 12,273	$ 2,533	$	$

Table of Contents

Mid-Con Energy Partners, LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

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

	Six Months Ended June 30,	
	2012	**2011**
Realized gain (loss) on derivatives, net	$ 769	$ (715)
Unrealized gain (loss) on derivatives, net	9,741	1,046
	$ 10,510	$ 331

Note 5. Fair Value Disclosures

Fair Value of Financial Instruments

The carrying amounts reported in our 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 rate 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 our 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

Table of Contents

Mid-Con Energy Partners, LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

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 as of June 30, 2012 and December 31, 2011:

	Level 1	Level 2	Level 3
		(in thousands)	
June 30, 2012			
Assets and Liabilities Measured at Fair Value on a Recurring Basis			
Derivative financial instruments - asset	$	$ 12,273	$
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis			
Asset retirement obligations	$	$	$ 699
December 31, 2011			
Assets and Liabilities Measured at Fair Value on a Recurring Basis			
Derivative financial instruments - asset	$	$ 2,533	$
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis			
Asset retirement obligations	$	$	$ 716

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 six months ended June 30, 2012.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

We estimate the fair value of the asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. See Note 6 for a summary of changes in asset retirement obligations.

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 its estimated fair value. 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.

Note 6. Asset Retirement Obligations

Asset retirement obligations (ARO) 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.

Table of Contents

Mid-Con Energy Partners, LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

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

Changes in our asset retirement obligations are as follows:

	Six Months Ended June 30, 2012	Year Ended December 31, 2011
	(in thousands)	
Asset retirement obligation beginning of period:	$ 1,919	$ 2,148
Liabilities incurred for new wells	278	370
Disposition of wells		(1,024)
Revision of estimates	421	347
Accretion expense	57	78
Asset retirement obligation end of period:	$ 2,675	$ 1,919

As of June 30, 2012 and December 31, 2011, $2.7 million and $1.9 million, respectively, of our ARO is classified as long-term and is reported as Asset Retirement Obligations in our unaudited condensed consolidated balance sheets.

Note 7. Debt

As of June 30, 2012, our credit facility consists of a $250.0 million senior secured revolving 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. The facility requires us and our subsidiary to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as such terms are defined in the Credit Agreement) of not more than 4.0 to 1.0, and a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0. As of June 30, 2012 and December 31, 2011, we were in compliance with all debt covenants.

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%, or 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 three months ended June 30, 2012, the average effective interest 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.

On April 23, 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. Borrowings under the facility may not exceed our current borrowing base of $100.0 million. The borrowing base is determined by our lenders based on the value of

Mid-Con Energy Partners, LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary. The borrowing base is subject to scheduled redeterminations 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.

On June 29, 2012, we borrowed an additional $14.0 million from our facility to acquire additional oil properties and working interests in our Northeastern Oklahoma and Southern Oklahoma core areas as explained in Note 2. of these financial statements.

At June 30, 2012, we had approximately $58.0 million in indebtedness outstanding under the facility.

Note 8. Commitment and Contingencies

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.

Note 9. Owners Equity

Common Units

At June 30, 2012, owners equity consisted of 17,789,561 common units, representing approximately a 98% limited partnership interest in us.

Cash Distributions

The following sets forth the distributions we paid during the six months ended June 30, 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
			$ 9,656

(1) The distribution represented a proration of initial quarterly distribution of $0.475 per unit.

On July 25, 2012, the board of directors of our general partner declared a quarterly cash distribution for the second quarter of 2012 of $0.475 per unit. The distribution of approximately $8.7 million is to be paid on August 14, 2012 to unitholders of record at the close of business on August 7, 2012.

Note 10. 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.

Table of Contents

Mid-Con Energy Partners, LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

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. During the six months ended June 30, 2012, we reimbursed Mid-Con Energy Operating approximately $1.3 million, respectively, for direct expenses.

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 fees). These costs are included in lease operating expenses in our unaudited consolidated statements of operations.

Note 11. New Accounting Standards

No new accounting pronouncements issued or effective during the six months ended June 30, 2012 have had or are expected to have a material impact on our consolidated financial statements.

Note 12. Subsequent Events

On July 25, 2012, the board of directors of our general partner declared a quarterly cash distribution for the second quarter of 2012 of $0.475 per unit, or $1.90 on an annualized basis. The distribution will be paid on August 14, 2012 to all unitholders of record as of the close of business on August 7, 2012. The aggregate amount of the distribution will be approximately $8.7 million.

Table of Contents

Mid-Con Energy Partners, LP

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 as of December 31, 2011 and 2010, and the related consolidated statements of operations, changes in equity, and cash flows for the years ended December 31, 2011 and 2010 and for the period from inception (July 1, 2009) to December 31, 2009. 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, 2011 and 2010, and the results of their operations and their cash flows for the years ended December 31, 2011 and 2010 and for the period from inception (July 1, 2009) to December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

March 9, 2012

Table of Contents

Mid-Con Energy Partners, LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors

Mid-Con Energy GP, LLC

We have audited the accompanying consolidated statements of operations, changes in equity and cash flows of Mid-Con Energy Corporation (a Delaware corporation) and subsidiaries for the year ended June 30, 2009. 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 audit.

We conducted our audit 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 audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of Mid-Con Energy Corporation and subsidiaries for the year ended June 30, 2009, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

August 12, 2011

Table of Contents

Mid-Con Energy Partners, LP and Subsidiaries

Consolidated Balance Sheets

(In thousands, except number of units)

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 228	$ 222
Accounts receivable:		
Oil and gas sales	5,018	2,134
Joint operations		1,544
Other	2,405	4
Certificate of deposit BIA bond		150
Inventory		771
Derivative financial instruments	1,028	
Prepaids and other	25	147
Total current assets	8,704	4,972
PROPERTY AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method:		
Proved properties	97,269	57,364
Unproved properties		446
Other property and equipment		2,324
Accumulated depletion, depreciation and amortization	(11,403)	(8,478)
Total property and equipment, net	85,866	51,656
OTHER ASSETS	536	239
DERIVATIVE FINANCIAL INSTRUMENTS	1,505	
Total assets	$ 96,611	$ 56,867
LIABILITIES AND OWNER S EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 4,575	$ 2,785
Accrued liabilities	138	399
Revenues payable		182
Other payables	1,630	
Advance billings		1,864
Notes payable, current portion		5,354
Derivative financial instruments		904
Total current liabilities	6,343	11,488
LONG-TERM DEBT	45,000	159
ASSET RETIREMENT OBLIGATIONS	1,919	2,148

EQUITY, per accompanying statements:		
Partnership equity General partner, representing a 2.0% interest, 360,000 notional units	1,299	
Limited partners, representing a 98.0% interest, 17,640,000 common units	42,050	
Members equity Contributed capital		52,923
Notes receivable from officers, director and employees		(1,833)
Accumulated deficit		(8,018)
Total equity	43,349	43,072
Total liabilities and equity	$ 96,611	$ 56,867

See accompanying notes to consolidated financial statements

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries and

Mid-Con Energy Corporation and subsidiaries

Consolidated Statements of Operations

(in thousands, except per unit data)

	Mid-Con Energy Partners, LP			Mid-Con Energy Corporation
	Year Ended December 31,		Six Months Ended December 31,	Year Ended June 30,
	2011	2010	2009	2009
Revenues:				
Oil sales	$ 36,813	$ 16,853	$ 5,729	$ 10,246
Natural gas sales	1,218	1,418	743	2,172
Realized loss on derivatives, net	(2,157)	(90)	(350)	(669)
Unrealized gain (loss) on derivatives, net	3,437	(707)	(147)	1,679
Total Revenues	39,311	17,474	5,975	13,428
Operating costs and expenses:				
Lease operating expenses	8,491	6,237	2,431	5,369
Oil and gas production taxes	1,869	822	269	631
Dry holes and abandonments of unproved properties	813	1,418		
Geological and geophysical	172	394		507
Depreciation, depletion and amortization	7,160	5,851	2,552	2,293
Accretion of discount on asset retirement obligations	78	127	58	78
General and administrative	1,924	982	704	1,767
Impairment of proved oil and gas properties		1,886	9,208	
Total operating costs and expenses	20,507	17,717	15,222	10,645
Income (loss) from operations	18,804	(243)	(9,247)	2,783
Other income (expense):				
Interest income and other	216	218	35	118
Interest expense	(578)	(98)	(2)	(93)
Gain on sale of assets	1,621	354		1
Equity-based compensation	(1,671)			
Other revenue and expenses, net	576	847	118	298
Total other income (expense)	164	1,321	151	324
Income before income taxes	18,968	1,078	(9,096)	3,107
Income tax expense current				(625)
Income tax expense benefit deferred				502
Total income tax (expense) benefit				(123)

Net income (loss)	$ 18,968	$ 1,078	$ (9,096)	$ 2,984
Computation of net income (loss) per limited partner unit:				
General partners interest in net income (loss)	$ 379	$ 22	$ (182)	
Limited partners interest in net income (loss)	$ 18,589	$ 1,056	$ (8,914)	
Net income (loss) per limited partner unit (basic and diluted)	$ 1.05	$ 0.06	$ (0.51)	
Weighted average limited partner units outstanding: (basic and diluted)	17,640	17,640	17,640	

See accompanying notes to consolidated financial statements

F-15

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries and

Mid-Con Energy Corporation and subsidiaries

Consolidated Statements of Cash Flows

(In thousands)

	Mid-Con Energy Partners, LP			Mid-Con Energy Corporation
	Year Ended December 31, 2011	Year Ended December 31, 2010	Six Months Ended December 31, 2009	Year Ended June 30, 2009
Cash Flows from Operating Activities:				
Net income (loss)	$ 18,968	$ 1,078	$ (9,096)	$ 2,984
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion and amortization	7,160	5,851	2,552	2,293
Accretion of discount on asset retirement obligations	78	127	58	78
Dry holes and abandonments of unproved properties	813	1,418		
Impairment of proved oil and gas properties		1,886	9,208	
Unrealized loss (gain) on derivative instruments, net	(3,437)	707	147	(1,679)
Gain on sale of assets	(1,621)	(354)		(1)
Equity-based compensation	1,671			
Deferred income taxes				(502)
Changes in operating assets and liabilities:				
Accounts receivable	(4,454)	(1,473)	(198)	373
Prepaids and other	442	539	(649)	21
Other assets		(134)	(100)	(54)
Inventory	(27)	(512)	37	(299)
Accounts payable	2,703	1,172	(381)	(549)
Accrued liabilities	275	7	(418)	664
Other accrued liabilities	1,630			
Revenues payable	32	46	5	(140)
Advance billings and other	(120)	1,440	(200)	7,978
Derivative financial instruments				(232)
Net cash provided by operating activities	24,113	11,798	965	10,935
Cash Flows from Investing Activities:				
Additions to oil and gas properties	(32,654)	(15,936)	(3,639)	(11,008)
Additions to other property and equipment	(679)	(922)	(734)	(360)
Acquisitions of oil and natural gas properties	(16,026)	(6,484)	(645)	(1,080)
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 affiliate, net of cash sold	4,000			
Net cash used in investing activities	(42,045)	(22,726)	(5,018)	(12,448)
Cash Flows from Financing Activities:				
Proceeds from line of credit	68,564	15,760		12,635
Payments on line of credit	(29,385)	(10,500)		(12,785)
Borrowings on note payable	412	10	351	
Payments on note payable	(84)	(94)	(16)	
Owners contributions		10,000		5,010

Proceeds from initial public offering, net of discount		87,397						
Distributions paid		(110,937)		(4,785)		(1,499)		
Repurchase of common units		(1)		(4)				
Issuance of common units		1,972						(19)
Net cash provided by (used in) financing activities		17,938		10,387		(1,164)		4,841
Net increase (decrease) in cash and cash equivalents		6		(541)		(5,217)		3,328
Beginning cash and cash equivalents		222		763		5,980		149
Ending cash and cash equivalents	$	228	$	222	$	763	$	3,477
Supplemental Cash Flow Information:								
Cash paid for interest	$	535	$	95	$	2	$	96
Non-Cash Investing and Financing Activities:								
Accrued capital expenditures oil and gas properties	$	3,331	$	1,209	$	178	$	2
Deferred gain on sale of property and equipment to subsidiary	$	1,208	$		$		$	
Notes receivable from officers, director and employees	$		$	635	$		$	137

See accompanying notes to consolidated financial statements

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries and

Mid-Con Energy Corporation and subsidiaries

Consolidated Statements of Changes in Equity

(In thousands)

	Series A Preferred Stock		Common Stock			Notes Receivable from Officers, Director and Employees	Treasury Stock			
MID-CON ENERGY CORPORATION	**Shares**	**Amount**	**Shares**	**Amount**	**Additional Paid-In Capital**		**Shares**	**Amount**	**Retained Earnings**	**Total Equity**
Balance, June 30, 2008	282	$ 3	347	$ 3	$ 28,068	$ (419)		$ (4)	$ 187	$ 27,838
Stock issuance	50		72	1	5,165	(156)				5,010
Stock repurchase						19	3	(38)		(19)
Net income									2,984	2,984
Balance, June 30, 2009	332	$ 3	419	$ 4	$ 33,233	$ (556)	3	$ (42)	$ 3,171	$ 35,813

MID-CON ENERGY PARTNERS, LP	**Contributed Capital**	**Notes Receivable from Officers, Directors and Employees**	**Accumulated Earnings/ (Deficit)**	**Total Equity**
		(in thousands)		
Balance, July 1, 2009	$ 48,572	$ (1,198)	$	$ 47,374
Distributions	(1,499)			(1,499)
Net loss			(9,096)	(9,096)
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

Limited Partner

	General Partner	Units	Amount	Total Equity
		(in thousands)		
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

See accompanying notes to consolidated financial statements

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements

Note 1. Organization and Nature of Operations

We are a publicly held Delaware limited partnership 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.

Mid-Con Energy Corporation (collectively, with its subsidiaries, the Corporation) was formed as a Delaware corporation on July 1, 2004. The Corporation had two wholly owned subsidiaries, RDT Properties, Inc. (RDT) and ME3 Oilfield Service, LLC (ME3). RDT (later re-named Mid-Con Energy Operating, Inc.) is the sole operator of mineral properties we own. ME3 provides oil field construction and maintenance services, as well as oil and water transportation services to us and to third parties.

On June 30, 2009, the Corporation and its subsidiaries, reorganized to form two separate Delaware limited liability companies, Mid-Con Energy I, LLC and Mid-Con Energy II, LLC (collectively with the subsidiaries of Mid-Con Energy II, LLC, the LLCs). As a result of this reorganization, the Corporation s mineral properties were transferred to the LLCs, along with the related accounts receivable, accounts payable and cash. RDT and ME3 were transferred to Mid-Con Energy II, LLC. The reorganization also resulted in issuance of full recourse notes receivable from certain officers, a director and shareholders, for the purchase of ownership units. See further discussion of these notes receivable in Note 9.

On June 30, 2011, Mid-Con Energy III, LLC, an affiliate of our general partner, purchased RDT, ME3 and certain oil and gas properties from the LLCs. Because this was a transaction of companies under common control, the excess of the cash that the LLCs received over the book value of the net assets transferred to Mid-Con Energy III, LLC was recorded as a capital contribution and no gain was recognized. The accompanying balance sheet as of December 31, 2011, reflects the sale of these subsidiaries and properties. The results of operations for these subsidiaries and properties are included in the accompanying statements of operations and cash flows up to the date of the sale.

In December 2011, in connection with the closing of our initial public offering (IPO) of common units, the LLCs merged with and into our wholly owned subsidiary, Mid-Con Energy Properties, LLC in exchange for a combination of common units issued and cash consideration paid to the LLCs owners.

On December 20, 2011 we completed our IPO of 5,400,000 common units at an initial public offering price of $18.00 per common unit. Our common units are traded on the NASDAQ Global Market under the symbol MCEP .

We used the net proceeds of approximately $87.4 million from this offering after deducting underwriting discounts, a structuring fee and offering expenses, together with borrowings of approximately $45.0 million under our new revolving credit facility to distribute approximately $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 the LLCs into our subsidiary at the closing of the offering. We also used the proceeds to repay in full $20.2 million of indebtedness outstanding under our existing credit facilities and to acquire, for aggregate consideration of approximately $6.0 million, certain working interests in the Cushing Field and certain derivative contracts from affiliated companies and interests. We did not use any of the net proceeds from the offering for investment in our business.

On January 9, 2012, the underwriters exercised in full their over-allotment option to purchase an additional 810,000 common units at the initial public offering price. Total net proceeds from the exercise of

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

the underwriters over-allotment option, after deducting estimated offering costs, were $13.6 million which, in accordance with the contribution agreement were distributed to certain employees, directors, and non-affiliates as consideration for assets contributed from the predecessors and reimbursements for pre-formation capital expenditures. Upon completion of the IPO, we had 17,640,000 limited partner units and 360,000 general partner units outstanding.

At December 31, 2011, our ownership structure was comprised of a 2.0% general partner interest held by Mid-Con Energy GP, LLC, a 63.5% limited partner interest held by the former owners of the LLCs and a 30.0% limited partner interest held by the public unitholders.

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, 2011 and 2010. These financial statements also include the results of our operations, cash flows and changes in equity for the years ended December 31, 2011 and 2010, and for the six months ended December 31, 2009 and the results of operations, cash flows and changes in equity of the Corporation for the year ended June 30, 2009. All intercompany transactions and account balances have been eliminated.

In the reorganization of the Corporation into the LLCs, the majority owner of the Corporation became the majority owner in the LLCs and made additional cash contributions to the LLCs. Therefore, we determined that the reorganization constituted a transaction between entities under common control. In comparison to the purchase method of accounting, whereby the purchase price for the asset acquisition would have been allocated to identifiable assets and liabilities of the LLCs based upon their fair values with any excess treated as goodwill, transfers between entities under common control require that assets and liabilities be recognized by the acquirer at carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to equity.

As discussed in Note 1, in addition to the cash contributions from the majority owner, in the reorganization of the Corporation into the LLCs, certain officers and directors of the LLCs purchased Class A Units in consideration of full recourse notes payable to the LLCs (see Note 9.) The LLCs also recognized an increase to equity of approximately $0.5 million related to elimination of deferred tax balances of the Corporation. As limited liability companies, the earnings or losses of the LLCs for federal and some state income tax purposes were included in the tax returns of the individual unitholders of the LLCs.

The merger of the LLCs into Mid-Con Energy Properties, LLC was considered a combination of businesses under common control, and as such the merger was accounted for in a manner similar to a pooling of interests. As a result, the accompanying historical financial statements give retrospective effect to the merger, whereby the assets and liabilities of the LLCs and us are reflected at the historical carrying values and their operations are presented as if they were consolidated for all periods.

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). 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.

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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 and our participation with other parties in the drilling, completion and operation of oil and gas wells. 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, 2011 and 2010, we did not have any reserves for doubtful accounts, and we did not incur any expenses related to bad debts in any period presented.

Joint interest and oil and gas sales receivables related to these operations are generally unsecured. Accounts receivable for joint interest billings were recorded as amounts billed to customers less an allowance for doubtful accounts. Amounts are considered past due after 30 days. Joint interest operations accounts receivable allowances are determined based on management s assessment of the creditworthiness of the joint interest owners and our predecessor s ability to realize the receivables through netting of anticipated future production revenues.

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, 2011 or 2010.

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,

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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.

We recognized approximately $9.2 million and $1.9 million as impairment charges against earnings for the six months ended December 31, 2009 and as of the year ended December 31, 2010, respectively, related to our proved oil and gas properties due to a significant decline in estimated proved and probable reserves 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 4. 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, 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 below expected performance for some of the waterflood units and other producing properties and revisions to the future expected drilling schedules. These impairments have no impact on our cash flow, liquidity position, or debt covenants. We had no impairments of proved oil and gas properties for the year ended December 31, 2011 and the Corporation had no impairments of proved oil and gas properties for the year ended June 30, 2009.

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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. The Corporation had no abandonments for the year ended June 30, 2009 and we had no abandonments for the period from July 1, 2009 to December 31, 2009. 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.

In January 2010, the Financial Accounting Standards Board (FASB) issued an accounting standards update that aligns the oil and natural gas reserve estimation and disclosure requirements of GAAP with the requirements in the final rule, *Modernization of the Oil and Gas Reporting Requirements*, issued in December 31, 2008 by the United States Securities and Exchange Commission (SEC) and effective for fiscal years ending on or after December 31, 2009. The new rules are intended to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves, which should help investors evaluate the relative value of oil and natural gas companies. The new rules permit the use of new technologies to determine proved reserves estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. The new rules also allow, but not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than a year-end price. We adopted the updated requirements as of December 31, 2009, which had the effect of adding 307 MBoe of proved reserves.

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. For the years ended December 31, 2011 and 2010 and for the six months ended December 31, 2009, depreciation expense related to other property and equipment totaled approximately $0.3 million, $0.6 million and $0.2 million, respectively. The Corporation recorded depreciation expense of $0.2 million for the year ended June 30, 2009. All of the other property and equipment was sold to Mid-Con Energy III, LLC at June 30, 2011.

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

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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 2010 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.

Inventory

Inventory consists primarily of oilfield equipment and is valued at the lower of cost or market. No excess or obsolete reserve has been recorded for the years ended December 31, 2011 and 2010. Our entire inventory was sold to Mid-Con Energy III, LLC at June 30, 2011.

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, $3.1 million and $1.2 million for the years ended December 31, 2011 and 2010, and for the six months ended December 31, 2009, respectively. These fees are now received by our affiliate, Mid-Con Energy Operating, Inc. The Corporation received such fees totaling $1.5 million for the year ended June 30, 2009.

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).

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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 $1.7 million for the year ended December 31, 2011.

Treasury stock

The Corporation recorded treasury stock purchased at cost. Upon reissuance, the cost of treasury stock was reduced by the average price per share of the aggregated treasury shares held. During the years ended June 30, 2009, the Corporation did not retire any treasury stock.

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.

We evaluate uncertain tax positions for recognition and measurement in the financial statements. To recognize a tax position, we determine whether it is more likely than not that the tax positions will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50% likely of being realized upon settlement. We have no uncertain tax positions that require recognition in the financial statements at December 31, 2011 or 2010. Any interest or penalties would be recognized as a component of income tax expense.

The Corporation accounted for income taxes in accordance with the asset and liability method under which deferred tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities were measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences were expected to be recovered or settled. The effect of deferred tax assets and liabilities of a change in tax rate was recognized in income in the period that included the enactment date.

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.

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

New accounting pronouncements

In January 2010, the FASB issued ASU No. 2010-06, *Fair Value Measurement and Disclosures (Topic 820),* which provides amendments to Topic 820. This amendment provides guidance that clarifies and requires new disclosures about fair value measurements. The clarifications and requirement to disclose the amounts and reasons for significant transfers between Level 1 and Level 2, as well as significant transfers in and out of Level 3 of the fair value hierarchy, were adopted by us in 2010. Note 4 Fair Value Measurements reflects the amended disclosure requirements. The new guidance also requires that purchases, sales, issuances, and settlements be presented on a gross basis in the Level 3 reconciliation and that requirement is effective for fiscal years beginning after December 15, 2009 and for interim periods within those years, with early adoption permitted. Since this new guidance only amends the disclosures requirements, it did not impact our operating results, financial position or cash flow.

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, 2011 had or are expected to have a material impact on our unaudited condensed financial statements.

Note 3. 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.

At December 31, 2011 and 2010 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.

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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

Months Outstanding	Settlement Price	Floor	Ceiling	Instrument Type	Total Barrels	NYMEX Index
Jan-Dec 2012	$ 104.28			Swap	72,000	WTI
Jan-Dec 2012	$ 100.00			Swap	96,000	WTI
Jan-Dec 2012	$ 99.95			Swap	60,000	WTI
Jan-Dec 2012	$ 100.97			Swap	120,000	WTI
Jan-Dec 2012		$ 100.00	$ 117.00	Collar	72,000	WTI
Jan-Dec 2013	$ 96.00			Swap	96,000	WTI
Jan-Dec 2013	$ 105.80			Swap	72,000	WTI
Jan-Dec 2013		$ 100.00	$ 111.00	Collar	72,000	WTI

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

At December 31, 2010 we had the following commodity derivative open positions:

Months Outstanding	Settlement Price	Floor	Ceiling	Instrument Type	Total Barrels	NYMEX Index
Jan 2011-Dec 2011	$ 83.25			Swap	18,000	WTI
Jan 2011-Dec 2011	$ 86.75			Swap	12,000	WTI
Jan 2011-Dec 2011	$ 85.30			Swap	12,000	WTI
Jan 2011-Dec 2011	$ 89.55			Swap	18,000	WTI

At December 31, 2010 we recorded the estimated fair value of $0.9 million for these derivative contracts as a current liability on the balance sheet.

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.

During the 4th quarter ending December 31, 2011 we unwound certain crude oil swaps prior to our IPO. The swap price of these contracts was significantly below the rest of our hedging contracts and we felt it was prudent to unwind and pay those off and replace them with swaps at a higher price prior to our IPO. This resulted in a charge to us of approximately $1.5 million which reduced net income for both the quarter and year ending December 31, 2011. This is reflected in our Consolidated Statements of Operations Realized loss on derivatives, net.

Through December 20, 2011, one of officers was entitled to, or responsible for, as applicable, 10% of the receivable or payable, respectively, on the monthly settlement from or to, as applicable, the derivative counterparty.

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

Note 4. 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.

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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, 2011 and 2010:

	Level 1	Level 2 (in thousands)	Level 3
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	$	$	$ 716
December 31, 2010			
Assets and Liabilities Measured as Fair Value on a Recurring Basis			
Derivative financial instrument - liability	$	$ 904	$
Assets and Liabilities Measured as Fair Value on a Nonrecurring Basis			
Asset retirement obligations	$	$	$ 319
Impairment of proved oil and gas properties	$	$	$ 1,886

Assets and liabilities measured at fair value on a nonrecurring basis

We estimate the fair value of the asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. See Note 5 for a summary of changes in asset retirement obligations.

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.

Note 5. Asset Retirement Obligations

Asset retirement obligations 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.

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

Our asset retirement obligations 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 asset retirement obligations by calculating the present value of estimated cash flow related to the liability. Each year we review and to the extent necessary, revise our asset retirement obligation estimates.

Changes in our asset retirement obligations and the Corporation s asset retirement obligations for the periods indicated are presented in the following table:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Six Months Ended December 31, 2009	Year Ended June 30, 2009
	(in thousands)			
Asset retirement obligation beginning of period	$ 2,148	$ 1,737	$ 1,569	$ 950
Liabilities incurred for new wells	370	265	115	70
Disposition of wells	(1,024)	(35)		
Revision of estimates	347	54	(5)	471
Accretion expense	78	127	58	78
Asset retirement obligation end of period	$ 1,919	$ 2,148	$ 1,737	$ 1,569

Note 6. Debt

As of December 31, 2011, our credit facility consists of a $250.0 million senior secured revolving facility that expires on December 16, 2016. Borrowings under the facility are secured by liens on not less than 80% of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general partnership purposes and for funding distributions to partners. The facility requires us and our subsidiaries to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as such term is defined in the Credit Agreement) of not more than 4.0 to 1.0, and a ratio of consolidated current assets to consolidated current liabilities 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, 2011, we were in compliance with all debt covenants.

Additionally, borrowings under the credit agreement will bear interest, at Mid-Con Energy Properties option, at either (i) the greater of the prime rate of the Royal Bank of Canada, the federal funds effective rate plus 0.50%, or the one month adjusted LIBOR plus 1.0%, all of which is 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. 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.

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

We had $45.0 million outstanding under the facility at December 31, 2011.

Debt at December 31, 2010 consisted of the following (in thousands):

Revolving credit facilities	$ 5,260
Term loan	253
	5,513
Less: Current portion	5,354
Long-term debt	$ 159

Prior to December 2011, we had two revolving credit facilities with a financial institution. Our oil properties located in southern Oklahoma were pledged as security under these agreements. During 2009, we entered into a variable rate term loan for approximately $350,000 with a final maturity in 2013. There were no outstanding letters of credit as of December 31, 2010. All borrowings were repaid with the proceeds from our initial public offering of common units.

All costs incurred in connection with the execution or modification of debt facilities were expensed as incurred based on the immateriality of costs.

Note 7. 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 $1.4 million to $1.7 million, including the value of vesting of any outstanding units.

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

Note 8. Owners Equity

Common Units

In December 2011, we completed our initial public offering of 5,400,000 common units at an initial public offering price of $18.00 per unit, and on January 9, 2012, we closed the sale of an additional 810,000 common units pursuant to the exercise of the underwriters over-allotment option. Upon the closing of our initial public offering, we had 17,640,000 limited partner units and 360,000 general partner units outstanding, representing a 98% limited partnership interest in us, and a 2.0% general partnership interest, respectively.

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.

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.

On January 25, 2012, the board of directors declared a quarterly cash distribution for the fourth quarter of 2011 of $0.057 per unit. The distribution represented a proration of our minimum quarterly distribution of $0.475 per unit for the period from December 21, 2011 through December 31, 2011. The aggregate distribution of $1.0 million was paid on February 13, 2012 to unitholders of record as of the close of business on February 6, 2012

Note 9. Related Party Transactions

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

Services Agreement

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,

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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, 2011, we reimbursed Mid-Con Energy Operating $0.2 million for direct expenses.

Assignment, Bill of Sale and Conveyance Agreement

We entered into an assignment, bill of sale and conveyance agreement 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 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 Contributing Parties, 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 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 accrued interest receivable was classified as other noncurrent assets on the balance sheet. 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, 2011 we had a net receivable from Mid-Con Energy Operating of $0.8 million which is comprised of a receivable from Mid-Con Energy Operating of $2.4 million and a separate payable of $1.6 million. These amounts are included in the Accounts receivable Other and Other payables, respectively, in our Consolidated Balance Sheets.

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

Note 10. 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.

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. These purchasers represented 83%, 9% and 6%, respectively, of our outstanding oil and natural gas accounts receivable at December 31, 2010.

For the six months ended December 31, 2009, purchases by Sunoco Logistics, ScissorTail Energy, LLC and Teppco Crude Oil, LLC accounted for 78%, 11% and 5%, respectively of our total sales revenues. For the year ended June 30, 2009, purchases by Sunoco Logistics, ScissorTail Energy, LLC and Teppco Crude Oil, LLC accounted for 69%, 16% and 5% of the Corporation s 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 11. Employee Benefit Plans

The partnership has a long-term incentive plan (the Plan) for employees, officers, consultants and directors of our general partner and its affiliates, including Mid-Con Energy Operating, who perform services for us. The Plan allows for the award of unit options, unit appreciation rights, restricted units, phantom units, distribution equivalent rights granted with phantom units, or other type of award. 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, 2011 all of the units are available for issuance.

Note 12. Income Taxes

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

The Corporation and its subsidiaries filed consolidated United States federal and state income tax returns. The tax returns and the amount of taxable income or loss reflected thereon are subject to examination by United States federal and state taxing authorities. An estimated tax payment of $0.6 million was made for the year ended June 30, 2009.

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

The reconciliation between the tax benefit (expense) computed by multiplying pretax income by the U.S. federal statutory income tax rate and the reported amounts of income tax benefit (expense) for the year ended June 30, 2009 is as follows:

U.S. federal statutory income tax rate	34.0%
State income taxes	4.0%
Percentage depletion in excess of tax basis	(32.7)%
Non-deductible permanent differences	(1.0)%
Other	(0.3)%
	4.0%

Note 13. Subsequent Events

Recognizable events

No recognizable events occurred during the period.

Non-recognizable events

On January 25, 2012, the board of directors declared a quarterly cash distribution for the fourth quarter of 2011 of $0.057 per unit. The distribution represented a proration of our minimum quarterly distribution of $0.475 per unit for the period from December 21, 2011 through December 31, 2011. The aggregate distribution of $1.0 million was paid on February 13, 2012 to unitholders of record as of the close of business on February 6, 2012.

In February 2012, the board of directors of our general partner authorized the issuance of 149,561 common units to certain employees and consultants of our affiliates and certain directors and founders of our general partner.

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

Note 14. Supplementary Information

Quarterly data (unaudited)

	Quarters Ended			
	March 30	June 30	September 30	December 31
	(In thousands, except per unit amounts)			
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)
2010				
Oil and natural gas sales	3,832	4,453	4,209	5,778
Realized gain (loss) on oil derivatives	(72)	(18)	4	(4)
Unrealized gain (loss) on oil derivatives	106	439	(364)	(889)
Total revenues and other	3,866	4,874	3,849	4,885
Total expenses(1)	3,886	4,147	3,996	5,688
Net income (loss)	610	882	72	(486)
Net income (loss) per unit:	598	864	71	(476)
Basic and diluted	$ 0.03	$ 0.05	$ 0.00	$ (0.03)

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

Supplementary oil and natural gas activities

	Mid-Con Energy Partners, LP			Mid-Con Energy Corporation
	Year Ended December 31		Six Months Ended	Year Ended
	2011	2010	December 31, 2009	June 30, 2009
	(in thousands)			
Property acquisition costs:				
Proved	$ 15,729	$ 6,483	$ 642	$ 1,080
Unproved		1	4	

Exploration		912		
Development	30,754	16,843	3,099	11,570
Asset retirement obligations	686	353	101	36
Total costs incurred	$ 47,169	$ 24,592	$ 3,846	$ 12,686

F-35

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

Estimated proved oil and natural gas reserves (unaudited)

The proved oil and gas reserves for the years ended December 31, 2011, and 2010 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:			
MID-CON ENERGY CORPORATION:			
As of July 1, 2008	5,339	1,772	5,634
Revisions of previous estimates	(618)	(517)	(704)
Extensions, discoveries and other additions	300	2	301
Purchases of minerals in place			
Production	(153)	(341)	(210)
As of June 30, 2009	4,868	916	5,021
MID-CON ENERGY PARTNERS:			
As of July 1, 2009	4,868	916	5,021
Revisions of previous estimates	1,293	29	1,298
Extensions, discoveries and other additions	113	4	114
Purchases of minerals in place	12		12
Production	(87)	(140)	(110)
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
Proved developed reserves:			
July 1, 2008 (Mid-Con Energy Corporation)	2,855	976	3,018

July 1, 2009	2,489	834	2,628
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
Proved undeveloped reserves:			
July 1, 2008 (Mid-Con Energy Corporation)	2,484	796	2,616
July 1, 2009	2,379	82	2,393
December 31, 2009	3,686		3,686
December 31, 2010	3,406		3,406
December 31, 2011	3,101		3,101

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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

During the twelve months ended June 2009, the quantities of proved reserves due to Extensions, discoveries and other additions were a result of the development of the Twin Forks Unit, and drilling development wells that offset the Southeast Hewitt Unit. For the twelve months ended June 2009, the Revisions of previous estimates were primarily due to significantly lower oil prices.

The change in quantities of proved reserves during the period from July 1, 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.

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, 2011 and 2010 and for the six months ended December 31, 2009 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. Sales prices used for oil and natural gas for the year ended June 30, 2009 were estimated using the year-end sales prices.

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.

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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:

	Mid-Con Energy Partners, LP.			Mid-Con Energy Corporation
	Year Ended		Six Months Ended	Year Ended
	December 31, 2011	December 31, 2010	December 31, 2009	June 30, 2009
	(in thousands)			
Future cash inflows	$ 930,788	$ 529,309	$ 343,595	$ 320,413
Future production costs	(297,490)	(152,913)	(109,344)	(101,045)
Future development costs	(34,504)	(26,802)	(26,447)	(13,673)
Future income tax expense				(66,268)
Future net cash flow	598,794	349,594	207,804	139,427
10% discount for estimated timing of cash flow	(270,563)	(165,932)	(102,004)	(61,547)
Standardized measure of discounted cash flow	$ 328,231	$ 183,662	$ 105,800	$ 77,880

The prices utilized in calculating our total proved reserves were $61.18, $79.43, and $96.19 per Bbl of oil and $3.83, $4.37, and $4.11 per MMBtu of natural gas for December 31, 2009, 2010, and 2011, 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 $54.92, $74.26 and $93.20 per Bbl of oil and $3.91, $7.36, and $7.04 per MMBtu of natural gas for December 31, 2009, 2010 and 2011, respectively. The prices utilized in calculating our total proved reserves, for June 30, 2009, were $69.89 per Bbl of oil and $3.84 per Mcf of natural gas. 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.

Table of Contents

Mid-Con Energy Partners, LP and subsidiaries

and Mid-Con Energy Corporation and subsidiaries

Notes to Consolidated Financial Statements (Continued)

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:

	Mid-Con Energy Partners Year Ended December 31, 2011	Mid-Con Energy Partners Year Ended December 31, 2010	Mid-Con Energy Partners Six Months Ended December 31, 2009	Mid-Con Energy Corporation Year Ended June 30, 2009
	(in thousands)			
Standardized measure of discounted future net cash flow, beginning of period	$ 183,662	$ 105,800	$ 77,880	$ 189,337
Changes in the year resulting from:				
Sales, less production costs	(27,671)	(11,212)	(3,772)	(6,418)
Revisions of previous quantity estimates	26,960	(9,278)	24,394	(16,928)
Extensions, discoveries and improved recovery	26,128	16,562	280	3,264
Net change in prices and production costs	79,618	44,773	(16,860)	(172,916)
Net change in income taxes			36,447	72,238
Changes in estimated future development costs	(30,521)	(2,170)	(11,081)	(2,795)
Previously estimated development costs incurred during the period	31,968	9,242	2,212	10,795
Purchases of minerals in place	20,200	22,330	161	
Accretion of discount	18,366	10,580	11,433	29,802
Timing differences and other	(479)	(2,965)	(15,294)	(28,499)
Standardized measure of discounted future net cash flow, end of year	$ 328,231	$ 183,662	$ 105,800	$ 77,880

F-39

Table of Contents

APPENDIX A GLOSSARY OF TERMS

The following includes a description of the meanings of some of the oil and gas industry terms used in this prospectus. 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: One Boe is equal to 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 or Well: 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.

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.

MBoe/d: One thousand Boe per day.

MBtu: One thousand Btu.

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.

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 shall be 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 SEC (using prices and costs in effect as of the date of estimation), 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: A crude oil produced in West Texas that is used as a benchmark for oil prices in the United States.

Table of Contents

Common Units

Mid-Con Energy Partners, LP

4,000,000 Common Units

Representing Limited Partner Interests

PRICE $21.20 PER COMMON UNIT

RBC CAPITAL MARKETS

RAYMOND JAMES

UBS INVESTMENT BANK

WELLS FARGO SECURITIES

BAIRD

OPPENHEIMER & CO.

STEPHENS INC.

PROSPECTUS

October 16, 2012