LRR Energy, L.P.
Form 10-K
March 04, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2014

OR

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

For the transition period from to

Commission File Number: 001-35344

LRR Energy, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**90-0708431** (I.R.S. Employer Identification No.)
Heritage Plaza **1111 Bagby Street, Suite 4600** **Houston, Texas** (Address of principal executive offices)	**77002** (Zip code)

Registrant s telephone number, including area code:
(713) 292-9510

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

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	**New York Stock Exchange**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x

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

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

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

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

Large accelerated filer o	**Accelerated filer** x
Non-accelerated filer o **(Do not check if a smaller reporting company)**	**Smaller reporting company** o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

As of June 30, 2014, the last business day of the registrant s most recently completed second fiscal quarter, the aggregate market value of the Common Units held by non-affiliates was $327,278,161 based on the closing price of $17.85 per unit on that date. For purposes of the calculation of aggregate market value, Fund I, which owned 4,089,600 Common Units on such date, is considered an affiliate of the registrant.

There were 28,074,433 common units and 22,400 general partner units outstanding as of February 27, 2015.

LRR Energy, L.P.

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GLOSSARY OF TERMS

The following includes a description of the meanings of some of the oil and gas industry terms used in this Annual Report on Form 10-K. 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.

Boe: One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

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.

Developed Acreage: The number of acres that are allocated or assignable to producing wells or wells capable of production.

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

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

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 a new field or find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross Acres or Gross Wells: The total acres or wells, as the case may be, in which we have working interest.

MBbls: One thousand Bbls.

MBoe: One thousand Boe.

MBtu: One thousand Btu.

Mcf: One thousand cubic feet of natural gas.

MMBoe: One million Boe.

MMBtu: One million Btu.

MMcf: One million cubic feet of natural gas.

Net Acres or Net Wells: The sum of our fractional working interests owned in gross acres or gross wells, as the case may be.

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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.

NGLs: The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

Oil: Crude oil and condensate and natural gas liquids.

Productive Well: A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

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 as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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.

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.

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

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

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

Undeveloped Acreage: Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

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

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

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

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

WTI: West Texas Intermediate.

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CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, and may include statements about our:

- *business strategies;*
- *ability to replace the reserves we produce through drilling and property acquisitions;*
- *drilling locations;*
- *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 flows and liquidity;*
- *availability of drilling and production equipment;*
- *general economic conditions;*
- *effectiveness of risk management activities; and*
- *plans, objectives, expectations and intentions.*

All statements, other than statements of historical fact, are forward-looking statements. These forward-looking statements can be identified by their use of terms and phrases such as may, predict, pursue, expect, estimate, project, plan, believe, intend, achievable, anticipate, target, continue, potential, should, could and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties some of which are beyond our control. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the statements under Risk Factors described in Item 1A. Risk Factors, which describe factors that could cause our actual results to differ from those anticipated in the forward-looking statements, including, but not limited to, the following factors:

- *our ability to generate sufficient cash to pay quarterly distributions on our common units;*
- *our ability to replace the oil and natural gas reserves we produce;*
- *our substantial future capital expenditures, which may reduce our cash available for distribution and could materially affect our ability to make distributions on our common units;*
- *a decline in, or substantial volatility of, oil, natural gas or NGL prices;*
- *the risk that oil and natural gas prices remain depressed for a prolonged period of time;*
- *the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production;*
- *the risk that our hedging strategy may be ineffective or may reduce our income;*
- *uncertainty inherent in estimating our reserves;*
- *the risks and uncertainties involved in developing and producing oil and natural gas;*
- *risks related to potential acquisitions, including our ability to make accretive acquisitions on economically acceptable terms or to integrate acquired properties;*
- *competition in the oil and natural gas industry;*
- *cash flows and liquidity;*
- *restrictions and financial covenants contained in the instruments governing our existing indebtedness;*
- *the availability of pipelines, transportation and gathering systems and processing facilities owned by third parties;*
- *electronic, cyber, and physical security breaches;*
- *general economic conditions; and*
- *legislation and governmental regulations, including climate change legislation and federal or state regulation of hydraulic fracturing.*

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All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document and speak only as of the date of this report. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

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PART I

ITEM 1. BUSINESS.

References in this Annual Report on Form 10-K to LRR Energy, Partnership, we, our, us or like terms refer collectively to LRR Energy, L.P., its wholly owned operating subsidiary, LRE Operating, LLC (OLLC), and its wholly owned subsidiary organized for the purpose of co-issuing its debt securities, LRE Finance Corporation (LRE Finance). References to Fund I or our predecessor refer collectively to Lime Rock Resources A, L.P. (LRR A), Lime Rock Resources B, L.P. (LRR B) and Lime Rock Resources C, L.P. (LRR C), which sold and contributed oil and natural gas properties and related net profits interests and operations to us in connection with our initial public offering (IPO). References to Fund II refer collectively to Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. References to Fund III refer to Lime Rock Resources III-A, L.P. and Lime Rock Resources III-C, L.P. References to Lime Rock Resources refer collectively to Fund I, Fund II and Fund III.

Overview

We are a Delaware limited partnership formed in April 2011 by Lime Rock Management LP (Lime Rock Management), an affiliate of Lime Rock Resources, to operate, acquire, exploit and develop producing oil and natural gas properties in North America with long-lived, predictable production profiles.

Our properties are located in the Permian Basin region in West Texas and Southeast New Mexico, the Mid-Continent region in Oklahoma and East Texas and the Gulf Coast region in Texas. As of December 31, 2014, our total estimated proved reserves were 33.8 MMBoe, of which approximately 88% were proved developed reserves (approximately 73% proved developed producing and approximately 15% proved developed non-producing). As of December 31, 2014, we operated 87% of our proved reserves. Our proved reserves had a standardized measure of $441.7 million as of December 31, 2014. For the year ended December 31, 2014, our average net production was 6,433 Boe/d.

Presentation

Each acquisition of properties from Fund I and Fund II in 2012 and 2013 was determined to be a transaction between entities under common control. As a result, our financial statements were revised to include the activities of such assets for all periods presented, similar to a pooling of interests, and to include the financial position, results of operations and cash flows of the assets acquired and liabilities assumed. See Note 2 to the Notes to the Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for more information on our accounting presentation.

Business Strategies

Our primary business objective is to generate stable cash flows to allow us to make quarterly cash distributions to our unitholders and, over time, to increase our quarterly cash distributions. To achieve our objective, we intend to execute the following business strategies:

- Leverage our relationship with Lime Rock Resources to provide additional acquisition opportunities through drop-down transactions and joint acquisitions.

- Pursue acquisitions of long-lived, low-risk producing oil and natural gas properties with reserve exploitation potential.

- Exploit opportunities on our current properties and manage our operating costs and capital expenditures.

- Reduce the impact of commodity price volatility on our cash flows through an active hedging program.

- Maintain a balanced capital structure to allow for borrowing capacity to execute our business strategies.

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Competitive Strengths

We believe the following competitive strengths will enable us to achieve our business strategies:

- Our diverse, predictable, long-lived reserve base with significant operational history under our control.
- Our significant inventory of low-risk projects on existing properties that we operate.
- Our relationship with Lime Rock Resources, which we expect will provide us with access to an inventory of additional mature oil and natural gas properties to acquire in drop-down transactions.
- Our experienced acquisition and operations team with a proven ability to identify, acquire and exploit long-lived oil and natural gas assets.
- Our balanced capital structure.

Principal Business Relationships

Our general partner is ultimately controlled by the co-founders of Lime Rock Management, who also ultimately control Lime Rock Resources and Lime Rock Partners. Lime Rock Resources, through Fund I, is our largest unitholder, owning a 30.5% limited partner interest in us as of December 31, 2014. In addition, through their interest in our general partner, Fund I and Fund II are collectively entitled to receive 100% of the distributions we make on our incentive distribution rights through November 16, 2017.

We believe our relationships with Lime Rock Management, Lime Rock Resources and Lime Rock Partners will increase our opportunities to acquire additional oil and natural gas properties from Lime Rock Resources and from Lime Rock Partners portfolio companies in the future, and will maximize our opportunities to participate in suitable acquisitions from third parties that otherwise may not be available to us. Additionally, these relationships provide us access to the management and operations team that manages and operates Lime Rock Resources.

Our Relationship with Lime Rock Management

Lime Rock Management was founded in 1998 and manages private capital for investment in the energy industry through its investment funds, Lime Rock Resources and Lime Rock Partners. All of our executive officers are employees of Lime Rock Management and provide services to us pursuant to the services agreement that we entered into with Lime Rock Management and Lime Rock Resources Operating Company, Inc. (ServCo), an affiliate of Lime Rock Resources, at the closing of our IPO, pursuant to which management, administrative and operational services are provided to our general partner and us to manage and operate our business. Mr. Jonathan Farber, a co-founder of Lime Rock Management and a Managing Director of Lime Rock Partners, and Mr. Townes Pressler, a Managing Director of Lime Rock Partners, serve on the board of directors of our general partner, and certain of our executive officers and non-independent directors own financial interests in Lime Rock Management.

Our Relationship with Lime Rock Resources

Lime Rock Resources was formed by Lime Rock Management for the purpose of acquiring mature, low-risk producing oil and natural gas properties with long-lived production profiles, and consists of three investment funds, Fund I, formed in 2005, Fund II, formed in 2008 and Fund III, formed in 2013. Lime Rock Resources successfully raised $456 million in equity commitments in Fund I, $410 million in equity commitments in Fund II and $762 million in equity commitments in Fund III and has a high quality team of 152 industry professionals who provide services to us pursuant to the services agreement. Since 2006, Lime Rock Resources has invested approximately (i) $416 million of Fund I equity and $277 million of Fund I leverage, (ii) $387 million of Fund II equity and $386 million of Fund II leverage, and (iii) $369 million of Fund III equity and $300 million of Fund III leverage in 21 major acquisitions of oil and natural gas properties in four diverse producing regions. Fund III has approximately $784 million of acquisition capacity that it expects to deploy over the next five years.

Lime Rock Resources is managed by Lime Rock Management and ServCo. Most of the executive officers of

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Lime Rock Resources, including Mr. Eric Mullins and Mr. Charles Adcock, Co-Chief Executive Officers of Lime Rock Resources, currently serve as executive officers of our general partner. In addition, our non-independent directors and executive officers, other than our Chief Financial Officer, own financial interests in Lime Rock Resources.

Lime Rock Resources had total estimated proved reserves of 66.5 MMBoe as of December 31, 2014, of which approximately 79% were proved developed reserves, with a standardized measure of $1.2 billion as of December 31, 2014 and average net production of approximately 10,638 Boe/d for the year ended December 31, 2014. The oil and natural gas properties owned by Lime Rock Resources include properties with characteristics similar to our properties, and Lime Rock Resources expects to invest additional capital into the further development of these properties. Following their successful development, we believe the majority of these properties will be suitable for acquisition by us in the future. Lime Rock Resources has informed us that it intends, from time to time, to offer us the opportunity to purchase some of its existing and future mature, producing oil and natural gas properties and to offer us the opportunity to participate in potential joint acquisition opportunities. Currently, 100% of Lime Rock Resources properties are onshore. However, Lime Rock Resources has no obligation to offer or sell any of its properties to us or share future joint acquisition opportunities with us, and any transactions with Lime Rock Resources would be subject to agreeing upon mutually acceptable terms. In addition, Lime Rock Resources and its affiliates, including any future affiliated funds and the exploration and production portfolio companies of Lime Rock Partners, are not limited in their ability to compete with us, including with respect to future acquisition opportunities. Please read Item 13. Certain Relationships and Related Transactions, and Director Independence.

We believe that we are well positioned to acquire additional oil and natural gas properties from Lime Rock Resources in the future in order to increase our reserves, production and cash distributions.

Our Relationship with Lime Rock Partners

Formed in 1998, Lime Rock Partners is a long-term investor of growth capital in energy companies worldwide. Lime Rock Partners objective is to generate substantial long-term capital appreciation through investments of private growth capital in energy companies in three principal sectors: (i) exploration and production; (ii) energy service; and (iii) oil service technology. Since 1998, Lime Rock Partners has raised approximately $4.0 billion in six funds. Although Lime Rock Partners does not invest directly in oil and natural gas properties, its exploration and production portfolio companies do invest in those types of assets. However, those portfolio companies typically target less mature or unconventional properties with higher growth and exploration potential than the properties we seek to acquire.

The Lime Rock Partners employees who provide services to Lime Rock Partners are experienced energy professionals with expertise in finance and operations and broad technical skills in the oil and natural gas industry. In connection with the business of Lime Rock Partners, these employees review a large number of potential acquisitions. Although Lime Rock Partners is not obligated to do so, Lime Rock Partners may refer new acquisition opportunities to us or the portfolio companies of Lime Rock Partners may sell their mature, low-risk oil and natural gas assets to us if mutually acceptable terms can be agreed to. In addition, Lime Rock Partners extensive investments in the energy service and oil service technology sectors may provide introductions, potential vendor relationships and industry intelligence that we believe will enable us to implement the latest services and technologies to increase production, maximize long-term reserve life and achieve cost containment. We believe we will benefit from the collective expertise of the employees who provide services to Lime Rock Partners, their extensive network of industry relationships and technologies, and the access to potential acquisition opportunities that would not otherwise be available to us.

Marketing and Major Customers

The following table indicates our significant customers that accounted for 10% or more of our total revenues for the periods indicated:

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	2014	2013	2012
Sunoco Partners Marketing & Terminals L.P.	22%	14%	17%
Phillips 66 Company	20%	18%	16%
Holly Frontier Refining & Marketing LLC	(1)	15%	(1)
Seminole Gas Company LLC	(1)	10%	(1)
Shell Trading (US) Company	(1)	(1)	10%

(1) The customers accounted for less than 10% of total revenues for the periods indicated.

Phillips 66 Company, Holly Frontier Refining & Marketing LLC, Sunoco Partners Marketing & Terminals L.P. and Shell Trading (US) Company purchase the oil production from us pursuant to existing agreements with terms that are currently on evergreen status and renew on a month-to-month basis until either party gives 30-day advance written notice of non-renewal. Seminole Gas Company LLC purchases natural gas production from us pursuant to an existing agreement that automatically renews on a year-to-year basis until either party gives six-month advance notice of termination prior to the end of such term.

If we were to lose any one of our significant customers, the loss could temporarily delay production and sale of our oil and natural gas in the related producing region. If we were to lose any single customer, we believe we could identify a substitute customer to purchase the impacted production volumes. However, if one or more of our larger customers ceased purchasing oil or natural gas altogether and we are unable to identify a substitute customer, this could have a detrimental effect on our production volumes in general.

Competition

We operate in a highly competitive environment for acquiring properties and securing qualified personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas 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 find 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, workover rigs, completion services and the availability of related equipment. 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. Beginning in the fourth quarter of 2014, commodity prices have significantly declined and we expect that the demand for this equipment and personnel to decline. We are unable to predict when, or if, shortages or surpluses of equipment and personnel may occur or how they would affect our development and exploitation programs.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months, resulting in seasonal fluctuations in the price we receive for our natural gas production. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of permits to conduct exploration, drilling and production operations;
- restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require investigatory and remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and
- impose substantial liabilities for pollution resulting from drilling and production operations.

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. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

These laws and regulations may also restrict the rate of oil and natural gas 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. In addition, federal, state and local authorities can seek to impose administrative, civil or criminal penalties for alleged non-compliance.

The 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, disposal, remediation or operational 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 give no assurance that we will continue to be in compliance or that compliance requirements will not become overly burdensome in the future.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate oil and natural gas production. Hydraulic fracturing is used to complete conventional vertical oil and gas wells. Hydraulic fracturing is also used to recover natural gas from deep shale formations in combination with horizontal drilling. Due to public concerns raised regarding the potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and as well as the state and local levels have been initiated to require or make more stringent permitting and compliance procedures for hydraulic fracturing operations. The U.S. Congress has considered legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of underground injection and could require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process. The U.S. Environmental Protection Agency, or EPA, commenced a multi-year study of the potential environmental impacts of hydraulic fracturing activities, and was expected to issue a report in 2014; however, it is not expected until 2016. In 2011, the EPA also announced its intention to propose regulations in 2015 under the Federal Water Control Act, as amended, also known as the Clean Water Act, to regulate wastewater discharges from hydraulic fracturing and other natural gas production processes. Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing, including states in which we operate. For example, New Mexico, Oklahoma and Texas adopted regulations which require disclosure of hydraulic fracturing fluids. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on

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allegations that specific chemicals used in the fracturing process could adversely affect groundwater. More recently, public concerns have been raised regarding the disposal of hydraulic fluids into injection wells.

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. Partly in response to public concerns, the Texas Railroad Commission amended its existing oil and gas disposal well regulations to require seismic activity data in permit applications and include provisions to authorize the imposition of certain limitations on existing wells if seismic activity increases in the area of an injection well, including a temporary injection ban.

Hydraulic fracturing has been a part of the completion process for newly drilled wells on most all of our producing properties in New Mexico, Texas and Oklahoma, and all of our properties are dependent on our ability to hydraulically fracture the producing formations with the exception of the undrilled locations on our properties in the Cowden Ranch area of Texas and Stroud area of Oklahoma. Substantially all of our leasehold acreage is currently held by production from existing wells. Therefore, fracturing is not currently required to maintain the current production or the leasehold acreage associated with our properties, but it will be required in the future to develop the proved non-producing and proved undeveloped reserves associated with this acreage. Nearly all of our proved non-producing and proved undeveloped reserves are associated with future drilling, recompletion, and fracture stimulation projects.

We follow applicable industry standard practices and legal requirements for groundwater protection in our operations, subject to close supervision by state and federal regulators (including the Bureau of Land Management on federal acreage), which conduct many inspections during operations that include hydraulic fracturing. These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by regulatory agencies, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval. Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abrupt change occurred to the injection pressure or annular pressure. In addition, we minimize the use of water and currently dispose of it in a way that minimizes the impact to nearby surface water by disposing excess water and water that is produced from the wells into approved disposal or injection wells. We currently do not discharge water on the surface.

Adoption of legislation amending the Safe Drinking Water Act or of any implementing regulations placing restrictions on hydraulic fracturing activities, including disposal, could impose operational delays, increased operating costs and additional regulatory burdens on our exploration and production activities, which could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Additional regulation of injection wells could increase the costs of disposal.

Hazardous Substances and Waste

The Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and their 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. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas, 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 and natural gas exploration, development and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future.

The 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 classes of persons considered to be responsible for the release of a hazardous substance into the

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environment, including damages to natural resources. Despite the petroleum exclusion under CERCLA, we may generate materials in the course of our operations that may be regulated as hazardous substances.

Numerous properties we own, lease, or operate have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. We could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The Clean Water Act and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and hazardous substances, into waters of the United States. The Oil Pollution Act of 1990, as amended, amends the Clean Water Act and establishes strict liability and natural resource damages liability for unauthorized discharges of oil into waters of the United States.

Air Emissions

The federal Clean Air Act 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 oil and natural gas projects. 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. For example, on August 16, 2012, the EPA published four sets of new rules that imposed new standards for air emissions from oil and natural gas development and production operations, which may require us to incur additional expenses to control air emissions from current operations and during new well developments by installing emissions control technologies and adhering to a variety of work practice and other requirements. We do not believe that these requirements will have a material adverse effect on our operations.

Climate Change

Scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. International protocols, federal, state, local and regional requirements could affect our operations. For example, the EPA has begun to regulate greenhouse gas emissions beginning with high-volume greenhouse gas emitters.

In June 2010, the EPA published its final rule to address the permitting of greenhouse gas, or GHG, emissions from stationary sources under the Prevention of Significant Deterioration and Title V permitting programs. This rule tailors these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Certain high-volume greenhouse gas emitters must also report these emissions. In November 2010, the EPA issued final rules that expand this GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. We began reporting GHG emissions from such facilities as required on an annual basis.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur and could result in increased costs and liabilities. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to

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incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that our products are competing with lower greenhouse gas emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur in an area where we operate, they could have an adverse effect on our assets and operations.

National Environmental Policy Act

Oil and natural gas 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 the Interior, to evaluate major agency actions having the potential to significantly impact the environment. Currently, we have production activities on federal lands. The NEPA review process has the potential to delay the development of oil and natural gas projects in these areas.

Endangered Species Act

Additionally, environmental laws such as the Endangered Species Act, as amended, or ESA, may impact exploration, development and production activities on public or private lands. ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the U.S. and prohibits taking of endangered 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 some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with ESA. However, the designation of additional endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

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

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Additionally, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the oil and natural gas industry with similar types, quantities and locations of production.

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Legislation continues to be introduced in Congress, and the development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, we do not believe that compliance with these laws will have a material adverse impact on our assets and operations.

Drilling and Production

Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow 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 and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Natural Gas and Oil Regulation

The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The FERC s regulation of interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of our properties.

Sales of crude oil, condensate and NGLs are not currently regulated and are made at market prices. However, Congress could reenact price controls in the future. Sales of crude oil are affected by the availability, terms and cost of transportation. The FERC also regulates interstate oil pipeline transportation rates.

State Regulation

The various states in which we own and operate properties regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. 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. The effect of these regulations may be to limit the amount of natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

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The petroleum 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 our assets and operations.

Insurance

We maintain insurance coverage against potential losses that we believe is customary in the industry. We currently maintain general liability insurance and excess liability insurance with limits of $1 million and $25 million per occurrence, respectively, and $2 million and $25 million in the aggregate, respectively. There is no deductible for our general liability insurance or our excess liability insurance. Our general liability insurance covers us for, among other things, legal and contractual liabilities arising out of property damage and bodily injury and for sudden or accidental pollution liability. Our excess 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 ranging from $5 million to $10 million and retentions ranging from $100,000 to $200,000. Our control of well policy insures us for blowout risks associated with drilling, completing and operating our wells, including above ground pollution.

Employees

Our general partner has sole responsibility for conducting our business and for managing our operations. However, neither we, our general partner nor our operating subsidiary have any employees. We are party to a services agreement with Lime Rock Management and ServCo pursuant to which management, administrative and operational services are provided to our general partner and us to manage and operate our business.

As of December 31, 2014, ServCo had 152 employees, including 12 engineering professionals, four geologist professionals and 13 land professionals, who provide services to Lime Rock Resources and us. As of December 31, 2014, Lime Rock Management had 23 employees that provided services to both Lime Rock Resources and us, and had one employee that provided services exclusively to us. Each of ServCo and Lime Rock Management has an agreement with Insperity PEO Services, L.P., a professional employer organization, pursuant to which Insperity provides them with full service human resources services in exchange for a service fee. As a result, all of the employees who will provide services to us are co-employees of Insperity. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations between ServCo and Lime Rock Management and their employees are satisfactory. We also contract for the services of independent consultants involved in land, engineering, regulatory, accounting, legal, financial and other disciplines as needed.

Offices

Lime Rock Management currently leases 56,984 square feet of office space in Houston, Texas at 1111 Bagby Street, Suite 4600, Houston, Texas 77002. Lime Rock Management allocates a portion of its lease expense to us for our proportionate share of the cost of the office space. The leases expire on March 31, 2024.

Available Information

We make available free of charge on our website, www.lrrenergy.com, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to the Securities Exchange Act of 1934, as amended (the Exchange Act), as soon as reasonably practicable after we electronically file such information with, or furnish it to, the Securities and Exchange Commission (SEC).

The information on our website is not, and shall not be deemed to be, a part of this Annual Report on Form 10-K or incorporated into any of our other filings with the SEC. These documents are also available on the SEC s website at www.sec.gov, or you may read and copy any materials that we file with or furnish to the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington D.C. 20549.

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ITEM 1A. RISK FACTORS.

Risks Related to Our Business

We may not have sufficient cash to pay quarterly distributions 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 quarterly distributions at the current distribution level, or any distribution at all, on our units. Under the terms of our partnership agreement, the amount of cash available for distribution will be reduced by our operating expenses and the amount of any cash reserves established by our general partner to provide for future operations, future capital expenditures, including development of our oil and gas properties, future debt service requirements and future cash distributions to our unitholders. The amount of cash we distribute on our units principally depends on the cash we generate from operations, which depends on, among other things:

- the amount of oil, NGLs and natural gas we produce and sell;
- the prices at which we sell our oil, NGL and natural gas production;
- the amount and timing of settlements on our commodity and interest rate derivatives;
- whether we are able to acquire additional oil and natural gas properties at economically acceptable prices;
- the level of our capital expenditures;
- the level of our operating costs, including development costs and payments to our general partner; and
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon.

Unless we replace the oil and natural gas 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 level without substantial capital expenditures that maintain our asset base. Producing oil and natural gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production and therefore our cash 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 drill additional wells or 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 development operations require substantial capital expenditures, which will reduce our cash available for distribution and could materially affect our ability to make distributions to our unitholders.

The development and production of our oil and natural gas reserves requires substantial capital expenditures, which will reduce the amount of cash available for distribution to our unitholders. Further, if the borrowing base under our credit facility or our revenues decrease as a result of lower oil or natural gas prices, we may not be able to obtain the capital necessary to sustain our operations at the expected levels necessary to generate an amount of cash sufficient to make distributions to our unitholders.

If oil and natural gas prices decline further or remain at current levels for a prolonged period, our cash flow from operations will decline, which could cause us to reduce our distributions or cease paying distributions altogether.

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

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

Historically, oil and natural gas prices have been extremely volatile. For example, for the five years ended December 31, 2014, the NYMEX-WTI oil price ranged from a high of $113.93 per Bbl to a low of $53.27 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $7.92 per MMBtu to a low of $1.82 per MMBtu. As of February 27, 2015, the NYMEX-WTI oil spot price was $49.76 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.75 per MMBtu. If oil and natural gas prices decline further or remain at current levels for a prolonged period, it may cause us to reduce or cease paying the distributions we pay to our unitholders.

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

Lower oil and natural gas prices may render many of our development and production projects uneconomical and result in a downward adjustment of our reserve estimates, which would negatively impact our borrowing base under our credit facility and ability to fund our operations. As a result, we may reduce the amount of distributions paid to our unitholders or cease paying distributions.

NYMEX-WTI oil prices have declined from $98.42 per Bbl on December 31, 2013 to $53.27 per Bbl on December 31, 2014. The reduction in price has been caused by many factors, including substantial increases in U.S. production and reserves from unconventional (shale) reservoirs, without an offsetting increase in demand. The International Energy Agency forecasts continued U.S. production growth and a slowdown in global demand growth in 2015. This environment could cause the prices for oil to remain at current levels or to fall to lower levels.

Furthermore, the recent decrease in oil and natural gas prices has reduced the number of our development projects that are economic. In addition, if oil and natural gas prices continue to remain depressed, our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. For example, we recorded an impairment of $37.8 million on our proved properties for the year ended December 31, 2014 in the Permian Basin and Mid-Continent regions. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period incurred. Finally, sustained low prices for oil and natural gas will negatively impact the value of our estimated proved reserves and the amount we are allowed to borrow under our credit facility and reduce the amounts of cash we would otherwise have available to pay expenses, make distributions to our unitholders and service our indebtedness.

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An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production could significantly reduce our cash available for distribution and adversely affect our financial condition.

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

Our hedging strategy may be ineffective in mitigating the impact of commodity price volatility from our cash flows, which could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders.

Our hedging strategy is to enter into commodity derivative contracts covering approximately 65% to 85% of our estimated production from total proved developed producing reserves over any subsequent three-to-five year period. The prices at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil and natural gas prices at the time we enter into these transactions, which may be substantially higher or lower than current oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil and natural gas prices received for our future production.

Our hedging activities could result in cash losses, could reduce our cash available for distributions and may limit potential gains.

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 and natural gas 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) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity.

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.

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 or natural gas in an exact way. Oil and natural gas reserve engineering is complex, requiring subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, future production levels and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. For example, if the prices used in our December 31, 2014 reserve reports had been $10.00 less per barrel for oil and $1.00 less per MMBtu for natural gas, then the standardized measure of our estimated proved reserves as of that date would have decreased by $98.2 million, from $441.7 million to $343.5 million.

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

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The standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves.

The present value of future net cash flows from our proved reserves, or standardized measure, may not be the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on 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 the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the FASB in Accounting Standards Codification (ASC) 932 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.

Developing and producing oil and natural gas are costly and high-risk activities 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.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. Furthermore, our development and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of rigs, equipment, labor or other services;
- unexpected operational events and conditions;
- adverse weather conditions and natural disasters;
- human errors and facility or equipment malfunctions, including pipe or cement failures, casing collapses or other downhole failures;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, discharge of toxic gas or other pollutants into the surface or subsurface environment;
- unusual or unexpected geological formations and pressure or irregularities in formations;
- loss of drilling fluid circulation;
- fires, blowouts, surface craterings and explosions;
- title problems; and
- uncontrollable flows of oil, natural gas or well fluids.

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

Our expectations for future drilling activities are scheduled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

We have identified and scheduled drilling locations as an estimation of our multi-year drilling activities on our acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs and drilling results. Because of these uncertainties, there may be significant delays in timing or we may realize lower than anticipated amounts of estimated proved reserves. Our actual drilling and enhanced recovery activities may materially differ from our current expectations, which could have a significant adverse effect on our financial condition and results of operations and as a result, ability to make cash distributions to our unitholders.

Shortages of rigs, equipment and crews could delay our operations and reduce our cash available for distribution to our unitholders.

Higher oil and natural gas prices generally increase the demand for rigs, equipment and crews and can lead to shortages of, and increasing costs for, development equipment, services and personnel. Shortages of, or increasing

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costs for, experienced development crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues and reduce our cash available for distribution to our unitholders.

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 and gas reserves. Even if we do 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, capital expenditures, operating expenses and costs;
- an inability to successfully integrate the assets we acquire;
- an inability to obtain satisfactory title to the assets we acquire;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;

- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;

- the diversion of management s attention from other business concerns;

- an inability to hire, train or retain qualified personnel to manage and operate our growing assets; and

- the occurrence of other significant changes, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges.

Our decision to acquire a property depends in part on our 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 acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition, given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

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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 located in New Mexico, Oklahoma and Texas. An adverse development in the oil and natural gas business of these geographic areas could have an impact on our results of operations and cash available for distribution 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.

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 oil and natural gas 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 and natural gas 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.

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 quarterly distributions at the current distribution level, or any distribution at all, 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 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 and term loan have restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders.

Our credit facility and term loan restrict, among other things, our ability to incur debt and pay distributions, and require us to comply with customary financial covenants and specified financial ratios. If market or other economic conditions deteriorate or if oil and natural gas prices remain depressed for a prolonged period, our ability to comply with these covenants may be impaired. If we violate any provisions of our credit facility or term loan that are not cured or waived within the specified time periods, a significant portion of our indebtedness may become immediately due and payable and we will be prohibited from making distributions to our unitholders. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our credit facility and term loan are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our credit facility or term loan, the lenders could seek to foreclose on our assets.

Our credit facility allows us to borrow up to the borrowing base, which is primarily based on the estimated future value of our oil and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. The borrowing base is redetermined by our lenders twice each year based on an engineering report with respect to our estimated reserves, based on commodity prices as of such date, as adjusted for the impact of our commodity derivative contracts. We expect the recent decline in commodity prices will result in a redetermination that lowers our borrowing base. Any future declines in commodity prices may also result in a redetermination that lowers our borrowing base. If the borrowing base is lowered to a level below our outstanding borrowings, we could be required to repay any indebtedness in excess of the borrowing base. If we are unable to repay any borrowings in excess of a decreased borrowing base, we would be in default and no longer able

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to make any distributions to our unitholders.

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

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

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

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

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

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our revolving credit facility and term loan bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income and cash available for distribution to our unitholders would decrease. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk Interest Rate Risk included under Part II of this annual report for further information regarding interest rate sensitivity.

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

The marketability of our oil, NGL and natural gas production depends in part on the availability, proximity and capacity of pipelines and other transportation methods, such as trucks, gathering systems and processing facilities owned by third parties. The amount of oil, NGLs and natural gas 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 contracted capacity on such systems. Also, the transfer of our oil and natural gas on third-party pipelines may be curtailed or delayed if it does not meet the quality specifications of the pipeline owners. Our access to transportation options, including trucks owned by third parties, can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. The curtailments arising from these and similar circumstances may last from a few days to more than a year. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or processing facility capacity could reduce our ability to market our oil and natural gas production and harm our business.

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We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas production operations are subject to complex and stringent laws and regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of oil and natural gas production. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to our unitholders.

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.

International protocols, federal, regional, state and local laws and regulations relating to climate change and greenhouse gases could cause our operating costs to increase. The EPA is reviewing mechanisms to adopt regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act beginning with large emitters. The EPA issued final rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published mandatory reporting rules for oil and gas systems requiring reporting starting in 2012 for emissions in 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil, natural gas and NGL that we produce.

Any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil, natural gas and NGLs that we produce.

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

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration and production activities. These costs and liabilities could arise under a wide range of federal, state 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, claims for damages to persons or property may result from environmental and other impacts of our operations.

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 were 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 third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulation. If existing laws and regulations governing such third

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party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to our unitholders.

A failure in our operational systems or cyber security attacks on any of our facilities or those of third parties may have a material adverse effect on our business.

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

Our operations are also subject to the risk of cyber security attacks. Any cyber security attacks that affect our facilities, our customers or our financial data could have a material adverse effect on our business. In addition, cyber security attacks on our customer and employee data may result in financial loss or potential liability and may negatively impact our reputation. Third-party systems on which we rely could also suffer system failures, which could negatively impact our business.

The derivatives provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, and related rules adopted and to be adopted by federal regulators could adversely affect our ability to use, and our cost of using, derivatives to mitigate the commodity price, interest rate and other risks associated with our business as well as our results of operations and liquidity.

Title VII of the Dodd-Frank Act, as amended, or Title VII, establishes a framework for federal oversight and regulation of over-the counter derivative transactions (generally referred to as swaps), including oil and gas hedging transactions and interest rate swaps, and participants in swaps and the market for swaps. The Commodity Futures and Trading Commission, or CFTC , federal banking regulators and the SEC have adopted and are adopting rules to implement Title VII s provisions. Under those provisions and related rules, parties to swaps of types designated by the CFTC for clearing on a derivatives clearing organization may have to clear those swaps and, in certain instances, execute trades in those swaps on other facilities. To date, the CFTC has designated only certain types of interest rate swaps and index credit default swaps for mandatory clearing, and it is unclear when the CFTC will designate other classes of swaps, such as physical commodity swaps, for mandatory clearing. If any of our swaps, including commodity swaps, are within a class of swaps designated for mandatory clearing or we decide to clear one or more of our swaps, we would have to post collateral in connection with those swaps that are cleared. Title VII and related rules provide an exception from the clearing and trade execution requirements for swaps that persons that are not financial entities (as defined in Title VII) enter into to hedge or mitigate their commercial risks. We intend to elect that exception for our swaps whenever possible. If we were characterized as a financial entity, however, we would be ineligible to elect that exception for any of the swaps we enter into. In that circumstance, our ability to execute our hedging program efficiently could be adversely affected.

The CFTC and banking regulators are in the process of adopting margin rules for uncleared swaps. As currently proposed, such margin rules do not impose any margin requirements on uncleared swaps to which non-financial end users of such swaps are parties. These rules are not final and how the final rules will affect us is uncertain at this time. It is possible that the CFTC and the banking regulators may ultimately adopt margin rules that may require us to post cash or other collateral with our counterparties for uncleared swaps to which we are a party. Our swap counterparties that are financial institutions subject to regulatory capital requirements may attempt to require us by contractual means to post cash or other collateral in connection with our swaps to which they are counterparties in order to reduce the amount of regulatory capital such counterparties are required to maintain with respect to their positions in such swaps. In addition, the CFTC is currently in the process of adopting rules that will limit the aggregate positions in certain commodity futures, option contracts and physical commodity swaps relating to one of 28 physical commodities, including light sweet crude oil, NY Harbor ULSD, RBOB gasoline and Henry Hub natural

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gas, that a person may maintain at any one time. These rules are not final and if and how the final rules will affect us is uncertain at this time.

Compliance with Title VII and the related rules adopted and to be adopted by the CFTC and other federal regulatory bodies may significantly increase our costs of operating our hedging program. Posting of cash collateral for either cleared or non-cleared swaps would reduce our liquidity, including our ability to use our cash for capital and other partnership expenditures, and could reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect our cash flows. Even if we are not required to clear our swaps or to post cash or other collateral for all or some of our swaps, our contractual counterparties could pass their costs of complying with Title VII and the related rules on to their customers, including us. Moreover, a Dodd-Frank Act provision may result in one or more of our counterparties spinning-off their derivative operations into separate entities. Separate entities could be our counterparties in our swaps in the future and may not be as creditworthy as our current counterparties. The changes in the U.S. derivative market resulting from Title VII and the related regulations could materially alter the terms of the swaps we enter, reduce the availability of some types of swaps that protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts and potentially increase our exposure to less creditworthy counterparties. If, as a result of the factors discussed above, we were to reduce our use of swaps to hedge the commodity price, interest rate and other risks we encounter, our results of operations and cash flows may become more volatile and be otherwise adversely affected. Moreover, Title VII was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If Title VII and the related regulations were to result in lower prices for oil and natural gas, our revenues could be adversely affected.

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

The U.S. Congress is considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is a commonly used process in the completion of unconventional natural gas wells in shale formations, as well as tight conventional formations including many of those that we complete and produce. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. If adopted, this legislation could establish an additional level of regulation and permitting at the federal level, and could make it easier for third parties to initiate legal proceedings based on allegations that chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil and surface water. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2015 under the Federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. Some states have adopted and others are also considering legislation to restrict and regulate hydraulic fracturing, including the disclosure of chemicals used in hydraulic fracturing. Recently, public concerns have been raised regarding the disposal of hydraulic fluid in injection wells. Partly in response to public concerns, the Texas Railroad Commission amended its existing oil and gas disposal well regulations to require seismic activity data in permit applications and provisions to authorize the imposition of certain limitations on existing wells if seismic activity increases in the area of an injection well, including a temporary injection ban. Any additional level of regulation could lead to operational delays or increased operating costs which could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and would increase our costs of compliance and doing business, resulting in a decrease of cash available for distribution to our unitholders.

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 accordingly. 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. The distribution yield of limited partner units 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.

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

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

We may experience a temporary decline in revenues and production if we lose one of our significant customers.

To the extent any one of our significant customers reduces the volume of its oil or gas purchases from us, we could experience a temporary interruption in sales of, or a lower price for, our oil and gas production and our revenues and cash available for distribution could decline which could adversely affect our ability to make cash distributions to our unitholders.

Expenses not covered by our insurance could have a material adverse effect on our financial position, results of operations and cash flows.

We maintain insurance coverage against potential losses that we believe is customary in the industry. However, these policies may not cover all liabilities, claims, fines, penalties or costs and expenses that we may incur in connection with our business and operations, including those related to environmental claims. In addition, we cannot assure you 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.

Risks Inherent in an Investment in Us

Our general partner and its affiliates own a controlling interest in us and will have conflicts of interest with us, and owe limited fiduciary duties to us, which may permit them to favor their own interests to the detriment of our unitholders.

Our general partner is ultimately controlled by the co-founders of Lime Rock Management, who also ultimately control Lime Rock Resources and Lime Rock Partners. In turn, our general partner has control over all decisions related to our operations. Lime Rock Resources, through Fund I, owns a 30.5% limited partner interest in us as of December 31, 2014 and, through Fund I s and Fund II s interests in our general partner, is entitled to receive 100% of the distributions we make on our incentive distribution rights through November 16, 2017. The directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to the owners of our general partner. However, our non-independent directors and certain of our executive officers hold similar positions with certain affiliates of our general partner, including Lime Rock Resources, Lime Rock Partners and Lime Rock Management, and continue to have economic interests, investments and other economic incentives in, as well as management and fiduciary duties to, these affiliates. As a result of these relationships, conflicts of interest may arise in the future between Lime Rock Resources, Lime Rock Partners and Lime Rock Management and their respective affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders and us. These potential conflicts include, among others, the following situations:

- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the 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 Lime Rock Resources, Lime Rock Partners or Lime Rock Management or their respective affiliates (other than our general partner) to pursue

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a business strategy that favors us. The directors and officers of Lime Rock Resources, Lime Rock Partners and Lime Rock Management 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;

- our general partner is allowed to take into account the interests of parties other than us, such as the owners of our general partner, in resolving conflicts of interest, which has the effect of limiting our general partner s fiduciary duty to our unitholders;

- Lime Rock Resources, Lime Rock Partners and Lime Rock Management 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, other than our Chief Financial Officer, also devote a significant amount of time to affiliates of our general partner, including Lime Rock Resources, and are compensated for services rendered to such affiliates;

- our general partner determines the amount and timing of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership interests, other investments, including investment capital expenditures in other partnerships 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 are a party to a services agreement with Lime Rock Management and ServCo pursuant to which management, administrative and operational services are provided to our general partner and us to manage and operate our business. Lime Rock Management and ServCo have similar arrangements with Lime Rock Resources and its affiliates;

- our general partner determines which costs, including allocated overhead, incurred by it and its affiliates, including Lime Rock Management and ServCo, are reimbursable by us. These expenses include salary, bonus, incentive compensation 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;

- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

- our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;

- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;

- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and

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

Please read Item 13. Certain Relationships and Related Transactions, and Director Independence.

Lime Rock Resources, Lime Rock Partners and other 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.

Neither our partnership agreement nor the omnibus agreement prohibits Lime Rock Resources, Lime Rock Partners and their affiliates from owning assets or engaging in businesses that compete directly or indirectly with us. For instance, Lime Rock Resources and any future affiliated funds may commence raising capital to make acquisitions once 75% of the capital of the most recent fund has been allocated to acquisition opportunities and expenses of such fund, and the portfolio companies of Lime Rock Partners may acquire, develop or dispose of oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets. Lime Rock Resources has approximately $784 million of acquisition capacity that it expects to deploy over the next several years. Because of Lime Rock Resources economic interests to invest those funds, it is likely that it will pursue acquisition opportunities that they may otherwise present to us. Lime Rock Resources and Lime Rock Partners are established participants in the energy business and have greater resources than ours, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for potential acquisitions. As a result, competition from these affiliates could adversely impact our results of operations and cash available for distribution to our unitholders. Additionally, if Lime Rock Resources fails to present us with acquisition opportunities, then we may not be able to replace or increase our estimated proved reserves, which would adversely affect our cash flow from operations and our ability to make cash distributions to our unitholders. Please read Item 13. Certain Relationships and Related Transactions, and Director Independence.

Neither we nor our general partner have any employees and we rely solely on Lime Rock Management and ServCo to manage our business. Most of our management team and the employees of ServCo provide substantially similar services to Lime Rock Resources, and thus are not solely focused on our business.

Neither we nor our general partner have any employees and we rely solely on Lime Rock Management and ServCo to manage us and operate our assets. We are a party to a services agreement with Lime Rock Management and ServCo pursuant to which management, administrative and operational services are provided to our general partner and us to manage and operate our business.

Lime Rock Management and ServCo provide substantially similar services and personnel to Lime Rock Resources. Should Lime Rock Resources form new funds, Lime Rock Management and ServCo may also enter into similar arrangements with those new funds. Because Lime Rock Management and ServCo provide services to us that are substantially similar to those provided to Lime Rock Resources and, potentially, other funds, Lime Rock Management and ServCo may not have sufficient human, technical and other resources to provide those services at a level that Lime Rock Management and ServCo would be able to provide to us if it did not provide those similar services to Lime Rock Resources and any other funds. Additionally, Lime Rock Management and ServCo may make internal decisions on how to allocate their available resources and expertise that may not always be in our best interest compared to those of Lime Rock Resources or other affiliated funds. There is no requirement that Lime Rock Management and ServCo favor us over Lime Rock Resources or other affiliated funds in providing their services. If the employees of Lime Rock Management and ServCo 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.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to continue to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002, as amended. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Most of the directors and officers who have responsibility for our management have significant duties with, and spend significant time serving, entities that 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 need to acquire oil and gas properties. Most of the directors and all of the officers of our general partner who are responsible for managing our operations and acquisition activities hold similar positions with Lime Rock Resources and other entities that are in the business, directly or indirectly, of identifying and acquiring oil and gas properties. For example, Mr. Farber, one of our general partner s directors, is a co-founder of Lime Rock Management and a managing director of Lime Rock Partners, which is in the business of investing in exploration and production companies. Mr. Pressler, one of our general partner s directors, is also a managing director of Lime Rock Partners, and Messrs. Mullins and Adcock, our

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general partner s Co-Chief Executive Officers, are also Co-Chief Executive Officers of Lime Rock Resources, which is in the business of acquiring oil and gas properties. All of the executive officers of our general partner, other than our Chief Financial Officer, devote significant time to Lime Rock Resources businesses. Further, our general partner s non-independent directors and certain of our executive officers have economic interests, investments and other economic incentives in affiliates of our general partner. Messrs. Farber and Pressler are also directors of several oil and gas producing entities that are in the business of acquiring oil and gas properties. The existing positions held by these directors and officers may give rise to fiduciary obligations that are in conflict with fiduciary duties they owe to us. The officers and directors of Lime Rock Resources, Lime Rock Partners and Lime Rock Management 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 with and economic interests in these and other entities, they may have fiduciary obligations 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 elect not to present them to us. These conflicts may not be resolved in our favor.

Cost reimbursements due to our general partner and its affiliates for services provided may be substantial and could reduce our cash available for distribution to our unitholders.

Under our services agreement with Lime Rock Management and ServCo, each of Lime Rock Management and ServCo receives reimbursement for the provision of various services and personnel for our benefit. Payments for these services are substantial and reduce the amount of cash available for distribution to unitholders.

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.

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

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

- a citizen of the United States;
- a corporation organized under the laws of the United States or of any state thereof;
- a public body, including a municipality; or
- 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.

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.

Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors. Affiliates of Lime Rock Management who control our general partner will have the power to control our operations.

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.

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Unitholders do not elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is appointed by Lime Rock Management. Furthermore, if our unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. 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.

Our general partner has control over all decisions related to our operations. Our general partner is ultimately controlled by the co-founders of Lime Rock Management, who also ultimately control Lime Rock Resources and Lime Rock Partners. As a result, our other unitholders will not have an ability to influence any operating decisions and will not be able to prevent us from entering into any transactions. Furthermore, the goals and objectives of our general partner and its affiliates relating to us may not be consistent with those of a majority of our other unitholders.

Our general partner is required to deduct estimated maintenance capital expenditures from our operating surplus, which may result in less cash available for distribution to unitholders from operating surplus than if actual maintenance capital expenditures were deducted.

Maintenance capital expenditures are those capital expenditures required to maintain the current production levels over the long term of our oil and natural gas properties or maintain the current operating capacity of our other capital assets, including expenditures to replace our oil and natural gas reserves (including non-proved reserves attributable to undeveloped leasehold acreage), whether through the development, exploitation and production of an existing leasehold or the acquisition or development of a new oil or natural gas property. Our partnership agreement requires our general partner to deduct estimated, rather than actual, maintenance capital expenditures from operating surplus in determining cash available for distribution from operating surplus. The amount of estimated maintenance capital expenditures deducted from operating surplus will be subject to review and change by our conflicts committee at least once a year. Our partnership agreement does not cap the amount of maintenance capital expenditures that our general partner may estimate. In years when our estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution to unitholders from operating surplus will be lower than if actual maintenance capital expenditures had been deducted from operating surplus. On the other hand, if our general partner underestimates the appropriate level of estimated maintenance capital expenditures, we will have more cash available for distribution from operating surplus in the short term but will have less cash available for distribution from operating surplus in future periods when we have to increase our estimated maintenance capital expenditures to account for the previous underestimation.

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 right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, common units, 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,

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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 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.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner s incentive distribution rights without the approval of the conflicts committee of our general partner or our unitholders. This may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (23%, in addition to distributions paid on its approximate 0.1% general partner interest) for each of the prior four consecutive fiscal quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the reset minimum quarterly distribution) and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of common units equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

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

The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove our general partner. As of December 31, 2014, Fund I owned 30.5% of our outstanding voting units, which, together with outstanding voting units held by affiliates of our general partner, would make it difficult for our public unitholders to remove our general partner.

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

Our general partner may transfer 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 owners of our general partner, who are affiliates of Lime Rock Management, from

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transferring all or a portion of their ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and thereby influence the decisions made by the board of directors and officers in a manner that may not be aligned with the interests of our unitholders.

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

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flow, including cash from reserves established by our general partner, working capital or other 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 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 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.

Fund I may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

As of December 31, 2014, Fund I owned an aggregate of 17.3% of our outstanding common units and all of our subordinated units, which convert into common units at the end of the subordination period. On February 13, 2015, all 4,480,000 subordinated units converted on a one-for-one basis into common units. The sale of these units, including common units issued upon the conversion of the subordinated units, in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a call right that may require common unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is the greater of (i) the highest cash price paid by either of our general partner or any of its affiliates for any common units purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those common units; and (ii) the average daily closing prices of our common units over the 20 days preceding the date three days before

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the date the notice is mailed. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Our unitholders also may incur a tax liability upon a sale of their common units. As of December 31, 2014, Fund I owned an aggregate of 17.3% of our outstanding common units and all of our subordinated units. On February 13, 2015, the 4,480,000 subordinated units converted on a one-for-one basis into common units. As of February 27, 2015, Fund I owned 30.5% of our aggregate outstanding common units.

If we distribute cash from capital surplus, which is analogous to a return of capital, our minimum quarterly distribution will be reduced proportionately, and the distribution thresholds after which the incentive distribution rights entitle our general partner to an increased percentage of distributions will be proportionately decreased.

Our cash distributions are characterized as coming from either operating surplus or capital surplus. Operating surplus is defined in our partnership agreement, and generally means amounts we receive from operating sources, such as sale of our oil and natural gas production, less operating expenditures, such as production costs and taxes, and less estimated average capital expenditures, which are generally amounts we estimate we will need to spend in the future to maintain our production levels over the long term. Capital surplus generally would result from cash received from non-operating sources such as sales of properties and issuances of debt and equity interests. Cash representing capital surplus, therefore, is analogous to a return of capital. Distributions of capital surplus are made to our unitholders and our general partner in proportion to their percentage interests in us, or approximately 99.9% to our unitholders and approximately 0.1% to our general partner, and will result in a decrease in our minimum quarterly distribution and a lower threshold for distributions on the incentive distribution rights held by our general partner.

Our partnership agreement allows us to add to operating surplus up to $30.0 million. As a result, a portion of this amount, which is analogous to a return of capital, may be distributed to the general partner and its affiliates, as holders of incentive distribution rights, rather than to holders of common units as a return of capital.

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

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

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

Our unitholders may have liability to repay distributions.

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

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We have the right to borrow to make distributions. Repayment of these borrowings will decrease cash available for future distributions, and covenants in our credit facility and term loan may restrict our ability to make distributions.

Our partnership agreement allows us to borrow to make distributions. We may make short-term borrowings under our credit facility to make distributions. The primary purpose of these borrowings would be to mitigate the effects of short-term fluctuation in our working capital that would otherwise cause volatility in our quarter-to-quarter distributions.

The terms of our credit facility and term loan contain covenants that restrict our ability to pay distributions in certain instances.

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.

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, NGLs and natural gas.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation or we were to become subject to material additional amounts of entity-level taxation for state purposes, then our cash available for distribution to our unitholders would be substantially reduced.

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

If we were treated as a corporation for U.S. federal income tax purposes (including, but not limited to, due to a change in our business or a change in current law), 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.

Changes in current state law may subject us to additional entity-level taxation by individual states or localities. 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.

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Our partnership agreement provides that if a law is enacted or an existing law is modified or interpreted in a manner that subjects us to additional amounts of entity-level taxation for U.S. federal, state or local income tax purposes, the minimum quarterly distribution amount and the Target Distribution may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time the Obama Administration and members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that would affect publicly traded partnerships. One such Obama Administration budget proposal for fiscal year 2016 would, if enacted, tax publicly traded partnerships with fossil fuels activities as corporations for U.S. federal income tax purposes beginning in 2021. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our units. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal income tax purposes, the minimum quarterly distribution and the Target Distribution may be adjusted to reflect the impact of that law on us.

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.

During past legislative sessions, both the Obama Administration and members of the U.S. Congress have proposed changes that would, if enacted, make significant changes to U.S. 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 with 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 U.S. 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 a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all 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 will be 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 will be treated as partners to whom we will allocate taxable income, which could be different in amount than the cash we distribute, our unitholders will be 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 tax basis in those units. Because 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 and IDC recapture. In addition, because the amount realized may include a unitholder s share of our nonrecourse liabilities, if they sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts, 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, state or local 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 depletion, depreciation and amortization positions that may not conform with all aspects of existing U.S. 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 audit adjustments to a unitholder s tax returns.

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, and although the U.S. Treasury Department has issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for U.S. 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 this purpose, multiple sales of the same unit will be counted only once. 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, as described below) for one fiscal year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder s taxable income for the year of termination. A technical termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a technical termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a technically terminated publicly traded partnership requests relief and such relief is granted, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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

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

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

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future even if such unitholders do not live in those jurisdictions. Our unitholders 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 a number of states, most of which currently impose a personal income tax on individuals. Most of 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.

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ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Our properties consist of mature, low-risk onshore oil and natural gas properties with long-lived, predictable production profiles located across three diverse producing regions: (i) the Permian Basin region in West Texas and Southeast New Mexico, (ii) the Mid-Continent region in Oklahoma and East Texas and (iii) the Gulf Coast region in Texas.

As of December 31, 2014, our total estimated proved reserves were 33.8 MMBoe, of which 73% were proved developed producing reserves. Our reserves are 52% oil and NGLs as measured by volume as of December 31, 2014. As of December 31, 2014, we operated 87% of our proved reserves and produced from 856 gross (745 net) wells across our operated properties, with an average working interest of 87%. Based on our reserve reports as of December 31, 2014, the estimated decline rate for our existing proved developed producing reserves is 11% per year for 2015 through 2020 and 7% per year thereafter. As of December 31, 2014, 5.1 MMBoe, or 15% of our estimated proved reserves, were proved developed non-producing reserves. Such estimated proved developed non-producing reserves were 57% oil and NGLs and included 296 gross (241 net) recompletion, refracture stimulation, workovers and return to production projects. In addition, as of December 31, 2014, 4.2 MMBoe, or 12% of our estimated proved reserves, were proved undeveloped reserves. Our proved undeveloped reserves were 67% oil and NGLs and included 208 gross (133 net) identified drilling locations.

Our properties are located in fields that generally have been producing for a long period of time, typically more than ten years. Observing the performance of these fields over many years allows for greater understanding of production and reservoir characteristics, making future performance more predictable. The production and corresponding decline rates attributable to properties of this type, in contrast with more recently drilled properties, can be forecasted with a greater degree of accuracy. Similarly, we use words such as mature or low-risk to describe our properties as having established operating, reservoir and production characteristics.

The development and production of oil and natural gas has a number of uncertainties that pose substantial risk, even for mature properties. However, we view our properties as having less risk because many of the operational risks associated with development and production (for example, drilling a well, whether one will encounter hydrocarbons capable of production in paying quantities and initial production decline rate) tend to occur earlier in the lifecycle of oil and natural gas properties. For a discussion of the risks inherent in oil and natural gas production, please read Item IA. Risk Factors Risks Related to Our Business.

The following table shows the estimated net proved oil and natural gas reserves of our properties as of December 31, 2014, based on the reserve reports prepared by Miller and Lents, Ltd. (Miller and Lents), Netherland, Sewell and Associates, Inc. (Netherland Sewell) and Ryder Scott Petroleum Consultants (Ryder Scott), our independent petroleum engineers, and certain unaudited information regarding such properties.

	Estimated Net Proved Reserves as of December 31, 2014 (1)					
	MBoe	**% of Total Reserves**	**% Proved Developed**	**% Oil and NGLs**	**% Operated**	**Standardized Measure (millions)**
Permian Basin Region	16,309	48%	88%	68%	94%	$ 257.2
Mid-Continent Region	14,225	42%	87%	39%	77%	156.6
Gulf Coast Region	3,311	10%	89%	33%	91%	28.5
All Regions	33,845	100%	88%	52%	87%	$ 442.3
Texas Margin Tax						(0.6)
						$ 441.7

(1) Our estimated net proved reserves were computed by applying average trailing twelve-month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the

applicable twelve-month period), held constant throughout the life of the properties. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The average trailing twelve-month index prices were $94.99/Bbl for NYMEX-WTI oil and $4.35/MMBtu for NYMEX-Henry Hub natural gas for the twelve months ended December 31, 2014. For NGL pricing, a differential is applied to the $94.99/Bbl average trailing twelve-month index price of oil.

Summary of Oil and Natural Gas Properties and Projects

The Permian Basin Region

Approximately 48% of our estimated proved reserves as of December 31, 2014 and 55% of our average daily net production for the year ended December 31, 2014 were located in the Permian Basin region. The Red Lake field accounted for 39% of our average daily net production for the year ended December 31, 2014. Approximately 68% of our estimated net proved reserves in the Permian Basin region are oil and NGLs. The Permian Basin is one of the largest and most prolific oil and natural gas producing basins in the United States, extending over 100,000 square miles in West Texas and Southeast New Mexico, and has produced over 29 billion barrels of oil since its discovery in 1921. The Permian Basin is characterized by oil and natural gas fields with long production histories, multiple producing formations and low rates of production decline. The majority of our current production in the Permian Basin region is primary recovery. However, waterflood operations exist in the same formations in nearby properties operated by others and the potential for similar operations exist in some of our wells that produce from the San Andres formation in our Red Lake area.

We own an 80% average working interest across 667 gross (531 net) wells and operate 94% of our proved reserves in the Permian Basin. Our estimated proved reserves for our Permian Basin properties as of December 31, 2014 totaled 16.3 MMBoe and had a standardized measure of $257.2 million, which represented 58% of the total standardized measure for all of our estimated proved reserves. Our Permian Basin properties have a proved developed producing production decline rate of 13% per year over the next five years and 8% thereafter. Based on our reserve reports dated December 31, 2014, we expect to spend $22.3 million on recompletions, re-stimulations, workovers and facility upgrades to convert our 3.4 MMBoe of Permian Basin proved developed non-producing reserves to proved developed producing reserves and $53.3 million on drilling to convert our 2.0 MMBoe of Permian Basin proved undeveloped reserves to proved developed producing.

The Mid-Continent Region

On October 1, 2014, we completed an acquisition of oil and natural gas properties in the Stroud field located in Lincoln and Creek Counties, Oklahoma for a purchase price of $38.0 million. The October 2014 Acquisition was effective September 1, 2014.

Approximately 42% of our estimated proved reserves as of December 31, 2014 and 35% of our average daily net production for the year ended December 31, 2014 were located in the Mid-Continent region. The Potato Hills field accounted for 18% of our average daily net production for the year ended December 31, 2014. Approximately 39% of our estimated net proved reserves in the Mid-Continent region are oil and NGLs. Our properties in the Mid-Continent Region are characterized by stratigraphic plays with multiple, stacked pay zones and more complex geology than our other operating areas. Similar to our other operating areas, the Mid-Continent region contains a number of fields with long production histories.

We own a 43% average working interest across 579 gross (251 net) wells and operate 77% of our proved reserves in the Mid-Continent region. Our estimated proved reserves for our Mid-Continent region properties as of December 31, 2014 were 14.2 MMBoe and had a standardized measure of $156.6 million, which represented 36% of the total standardized measure for all of our estimated proved reserves. Our Mid-Continent properties have a proved developed producing production decline rate of 8% per year over the next five years and 6% per year thereafter. Based on our reserve reports dated December 31, 2014, we expect to spend $2.9 million on recompletions and workovers to convert our 0.9 MMBoe of Mid-Continent proved developed non-producing reserves to proved developed producing reserves and $31.4 million on drilling to convert our 1.8 MMBoe of Mid-Continent proved undeveloped reserves to proved developed producing.

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The Gulf Coast Region

Approximately 10% of our estimated proved reserves as of December 31, 2014 and 10% of our average daily net production for the year ended December 31, 2014 were located in the Gulf Coast region. Approximately 33% of our estimated net proved reserves in the Gulf Coast region are oil and NGLs. Although many assets in the Gulf Coast region exhibit high rates of production decline, our Gulf Coast properties consist primarily of legacy fields and are characterized by relatively stable production profiles and long production histories.

We own a 68% average working interest across 46 gross (31 net) wells and operate 91% of our proved reserves in the Gulf Coast region. Our estimated proved reserves as of December 31, 2014 totaled 3.3 MMBoe and had a standardized measure of $28.5 million as of December 31, 2014, which represented 6% of the total standardized measure for all of our estimated proved reserves. Our Gulf Coast properties have a proved developed producing production decline rate of 11% per year over the next five years and 9% per year thereafter. Based on our reserve reports dated December 31, 2014, we expect to spend $1.2 million on recompletions and workovers to convert our 0.8 MMBoe of Gulf Coast proved developed non-producing reserves to proved developed producing reserves and $6.2 million on drilling to convert our 0.4 MMBoe of Gulf Coast proved undeveloped reserves to proved developed producing.

Oil and Natural Gas Data and Operations

Internal Controls

Our proved reserves are estimated at the well or unit level and compiled for reporting purposes by ServCo s corporate reservoir engineering staff. ServCo maintains internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interacts with ServCo s internal production and geoscience professionals in each of our operating areas and with operating, accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed internally by our senior management on a periodic basis throughout the year. Our reserve estimates are prepared by Miller and Lents, Netherland Sewell, and Ryder Scott, our independent third-party reserve engineers, at least annually.

Our internal professional staff works closely with Miller and Lents, Netherland Sewell and Ryder Scott to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, we provide Miller and Lents, Netherland Sewell and Ryder Scott other pertinent data, such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their evaluation of our reserves.

Technology Used to Establish Proved Reserves

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

To establish reasonable certainty with respect to our estimated proved reserves, Miller and Lents, Netherland Sewell and Ryder Scott employed 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

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data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and proved undeveloped locations and additions to proved undeveloped reserves were estimated using performance, log and production data from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

Qualifications of Responsible Technical Persons

Internal Engineer. Christopher Butta, Senior Vice President of Engineering and Chief Engineer of our general partner, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Mr. Butta is also responsible for liaison with and oversight of our third-party reserve engineers. Mr. Butta has 30 years of industry experience. From 1991 through 2005, Mr. Butta worked at Miller and Lents, an independent oil and gas consulting firm. During his 14 years at Miller and Lents, he rose from Consulting Engineer to Senior Vice President. From 1984 to 1991, Mr. Butta worked at ARCO Oil and Gas Company. He holds a Bachelor of Science degree in Petroleum Engineering from University of Missouri-Rolla.

Miller and Lents. Miller and Lents is an independent oil and natural gas consulting firm. No director, officer, or key employee of Miller and Lents has any financial ownership in us, ServCo, Lime Rock Resources or any of their respective affiliates. Miller and Lents compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported, and Miller and Lents has not performed other work for ServCo, Lime Rock Resources or us that would affect its objectivity. The independent engineering analysis presented in the Miller and Lents report was overseen by Ms. Leslie Fallon. Ms. Fallon is an experienced reservoir engineer having been a practicing petroleum engineer since 1983. She has more than 31 years of experience in reserves evaluation. She has a Bachelor of Science degree in Mechanical Engineering from The University of Texas at Austin and is a Registered Professional Engineer in the State of Texas.

Netherland Sewell. Netherland Sewell is an independent oil and natural gas consulting firm. No director, officer, or key employee of Netherland Sewell has any financial ownership in us, ServCo, Lime Rock Resources or any of their respective affiliates. Netherland Sewell s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported, and Netherland Sewell has not performed other work for ServCo, Lime Rock Resources or us that would affect its objectivity. The independent engineering analysis presented in the Netherland Sewell report was overseen by Mr. Lee E. George. Mr. George is an experienced reservoir engineer having been a practicing petroleum engineer since 1981. He has more than 33 years of experience in reserves evaluation. He has a Bachelor of Science degree in Civil Engineering from The University of Texas at Austin and is a Registered Professional Engineer in the State of Texas.

Ryder Scott. Ryder Scott is an independent oil and natural gas consulting firm. No director, officer, or key employee of Ryder Scott has any financial ownership in us, ServCo, Lime Rock Resources or any of their respective affiliates. Ryder Scott s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported, and Ryder Scott has not performed other work for ServCo, Lime Rock Resources or us that would affect its objectivity. The independent engineering analysis presented in the Ryder Scott report was overseen by Mr. William K. Fry. Mr. Fry is an experienced reservoir engineer having been a practicing petroleum engineer since 1975. He has more than 40 years of experience in reserves evaluation. He has a Bachelor of Science degree in Mechanical Engineering from Kansas State University and is a Registered Professional Engineer in the State of Texas.

Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves attributable to our properties, and the standardized measure amounts associated with such reserves, as of December 31, 2014, prepared by Miller and Lents, Netherland Sewell and Ryder Scott, our independent reserve engineers. All of our reserve estimates have been prepared by independent reserve engineers. The standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

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Reserve Data(1):		
Estimated proved reserves:		
Oil (MBbls)		13,106
NGLs (MBbls)		4,618
Natural gas (MMcf)		96,725
Total estimated proved reserves (MBoe)(2)		33,845
Estimated proved developed reserves:		
Oil (MBbls)		10,962
NGLs (MBbls)		3,956
Natural gas (MMcf)		88,265
Total estimated proved developed reserves (MBoe)(2)		29,629
Estimated proved undeveloped reserves:		
Oil (MBbls)		2,144
NGLs (MBbls)		662
Natural gas (MMcf)		8,460
Total estimated proved undeveloped reserves (MBoe)(2)		4,216
Standardized Measure (in millions)(3)	$	441.7

(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 $94.99/Bbl for NYMEX-WTI oil and NGLs and $4.35/MMBtu for NYMEX-Henry Hub natural gas at December 31, 2014. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. For NGL pricing, a differential is applied to the unweighted arithmetic average first-day-of-the-month oil prices for the prior twelve months. As of December 31, 2014, the relevant average realized prices for oil, natural gas and NGLs were $89.23 per Bbl, $4.41 per Mcf and $33.11 per Bbl, respectively.

(2) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on a rough energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(3) Standardized measure is calculated in accordance with ASC 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 Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Commodity Derivative Contracts.

The data in the table above represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. For a discussion of risks associated with reserve estimates, please read Item IA. Risk Factors Risks Related to Our Business.

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 and natural gas reserves. The 10% discount factor used to calculate standardized measure, which is required by Financial Accounting Standard Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Development of Proved Undeveloped Reserves

The following table represents a summary of activity within our proved undeveloped reserve category for the year ended December 31, 2014:

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	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved undeveloped reserves-beginning of year	2,150	717	4,450	3,609
Transferred to proved developed through drilling	(674)	(253)	(1,261)	(1,137)(1)
Increase (decrease) due to evaluation reassessments and drilling results, net	92	148	5,047	1,081(2)
Acquisition of reserves	576	50	224	663
Reductions of proved developed reserves aged five or more years				
Proved undeveloped reserves-end of period	2,144	662	8,460	4,216

(1) Represents the results of the drilling at our Red Lake and Putnam fields during 2014.

(2) Primarily represents natural gas wells that became economic during 2014.

We incurred $19.2 million in capital to convert proved undeveloped reserves to proved developed reserves during the year ended December 31, 2014.

All of our proved undeveloped reserves as of December 31, 2014 are scheduled to be developed on a date that is five years or less from the date the reserves were initially booked as proved undeveloped. We fund our drilling and development programs primarily from our cash flow from operations. Based on our current expectations of our cash flows and drilling and development programs, which includes drilling of proved undeveloped locations, we believe that we can fund the drilling of our current inventory of proved undeveloped locations in the next five years from our cash flow from operations and, if needed, our credit facility. For a more detailed discussion of our liquidity position, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Production, Revenues and Price History

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

Drilling and Other Exploratory and Development Activities

Drilling Activities. As of December 31, 2014, we were drilling one well, recompleting one well, testing six new wells, and production testing one well recompletion.

The following table sets forth information with respect to wells drilled and completed by us 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.

	2014		2013		2012	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development wells:						
Productive	43	23	32	18	17	14
Dry						
Exploratory wells:						
Productive						
Dry						
Total wells:						
Productive	43	23	32	18	17	14
Dry						
Total	43	23	32	18	17	14

Other Exploratory and Development Activities. As of December 31, 2014, we did not have any exploratory activities in progress on our properties.

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Productive Wells

The following table sets forth information at December 31, 2014 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 approximately the sum of our fractional working interests owned in gross wells.

	Oil		Natural Gas	
	Gross	**Net**	**Gross**	**Net**
Operated	406	361	450	384
Non-operated	274	38	151	29
Total	680	399	601	413

Acreage

The following table sets forth information as of December 31, 2014 relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2014, substantially all of our leasehold acreage was held by production and no material acreage is set to expire in the near term.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross (1)	**Net (2)**	**Gross (1)**	**Net (2)**	**Gross (1)**	**Net (2)**
Permian Basin	146,228	121,058	3,180	944	149,408	122,002
Mid-Continent	126,163	22,180	20,590	5,158	146,753	27,338
Gulf Coast	12,597	8,616	240	153	12,837	8,769
Total	284,988	151,854	24,010	6,255	308,998	158,109

(1) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.

(2) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Delivery Commitments

We have no delivery commitments with respect to our production.

Exploitation Activities

Reserve additions due to extensions and discoveries are primarily in the proved undeveloped reserve category. As of December 31, 2014, we have identified 296 gross (241 net) recompletion, refracture stimulation, workovers and return to production projects and 208 gross (133 net) proved undeveloped drilling locations on our properties. Excluding acquisitions, we anticipate capital expenditures of approximately $43.4 million during the twelve months ending December 31, 2014, including drilling 53 gross (32 net) development wells and executing 141 gross (122 net) recompletions, refracture stimulations, workovers and return to production projects.

Operations

General

As of December 31, 2014, we operated 87% of our proved reserves. 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. Independent contractors provide all the equipment and personnel associated with these activities.

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Pursuant to our services agreement with ServCo and Lime Rock Management, ServCo and Lime Rock Management provide management, administrative and operational services to our general partner and us to manage and operate our business. ServCo employs production and reservoir engineers, geologists and other specialists, as well as field personnel. We charge the non-operating partners a contractual administrative overhead charge for operating the wells. Some of our non-operated wells are managed by third-party operators who are typically independent oil and natural gas companies.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties range from 1% to 54%, and we have a net revenue interest to us ranging from 0% to 88%, or 57% on average for most of our leases.

Substantially all of our leases are held by production and are not subject to continuous drilling obligations.

Title to Properties

Prior to completing an acquisition of producing oil and natural gas 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.

As is customary in the oil and natural gas industry, we initially conduct only a cursory 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 report.

ITEM 3. LEGAL PROCEEDINGS.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, neither we nor our general partner is currently a party to any material legal proceedings. In addition, we are not aware of any significant legal or governmental proceedings against us or our general partner, or contemplated to be brought against us or our general partner, under the various environmental protection statues to which we or they are subject.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

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PART II

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

Our common units are listed and traded on the NYSE under the symbol LRE. As of February 27, 2015, there were 28,074,433 common units outstanding held by 31 holders of record, including common units held by Lime Rock Resources. This number does not include owners from whom common units may be held in street name. The table below represents the daily high and low sales price per common unit for the years ended December 31, 2014 and 2013.

	Common Unit Price Range	
	High	Low
2014		
Fourth quarter	$ 18.04	$ 6.57
Third quarter	$ 20.11	$ 17.10
Second quarter	$ 18.36	$ 16.90
First quarter	$ 18.16	$ 16.01
2013		
Fourth quarter	$ 18.45	$ 15.75
Third quarter	$ 16.15	$ 13.41
Second quarter	$ 18.28	$ 13.13
First quarter	$ 19.20	$ 18.78

We have issued 22,400 general partner units to LRE GP, LLC.

Cash Distributions to Unitholders

			Limited Partners (in thousands)				
				Affiliated			
Date Paid	For the quarterly period ended	General Partner	Public Common	Common	Subordinated	Total Distributions	Distribution Per Unit
February 14, 2013	December 31, 2012	$ 11	$ 5,125	$ 2,424	$ 3,225	$ 10,785	$ 0.4800
May 15, 2013	March 31, 2013	11	8,492	892	3,242	12,637	0.4825
August 14, 2013	June 30, 2013	11	8,536	897	3,259	12,703	0.4850
November 14, 2013	September 30, 2013	11	8,579	902	3,276	12,768	0.4875
February 14, 2014	December 31, 2013	11	8,674	921	3,278	12,884	0.4900
May 15, 2014	March, 31, 2014	11	8,874	911	3,310	13,106	0.4925
August 14, 2014	June 30, 2014	11	9,346	2,024	2,218	13,599	0.4950
November 14, 2014	September 30, 2014	11	9,564	2,035	2,229	13,839	0.4975
February 13, 2015	December 31, 2014	11	9,704	2,034	2,229	13,978	0.4975

Cash Distribution Policy

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date.

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

- *less*, the amount of cash reserves established by our general partner at the date of determination of available cash for the quarter to:

- provide for the proper conduct of our business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;

- comply with applicable law, any of our debt instruments or other agreements; or

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- provide funds for distributions to our unitholders (including our general partner) for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for future distributions to our unitholders unless it determines that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for such quarter);

- *plus*, if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.

As of December 31, 2014, Fund I owned an aggregate of 4,480,000 subordinated units. During the subordination period, the common units had the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.4750 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus could be made on the subordinated units. These units were deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units were not entitled to receive any distributions from operating surplus until the common units had received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages were paid on the subordinated units. The practical effect of the subordinated units was to increase the likelihood that during the subordination period there would be available cash from operating surplus to be distributed on the common units.

The subordination period ended on February 13, 2015, the first business day of any quarter after December 31, 2014 that we had earned and paid from operating surplus, in the aggregate, distributions on each outstanding common unit, subordinated unit and general partner unit and any other partnership interests that are senior or equal in right of distribution to the subordinated units equaling or exceeding the minimum quarterly distribution payable with respect to a period of twelve consecutive quarters immediately preceding such date, and there were no arrearages in the minimum quarterly distribution on our common units at that time. However, three separate one third tranches of subordinated units could convert on the first business day after the distribution to unitholders in respect of any quarter ending on or after December 31, 2012, December 31, 2013 and December 31, 2014, respectively, provided that an aggregate amount equal to the minimum quarterly distribution payable with respect to all units that would be payable on four, eight or twelve consecutive quarters, as applicable, had been earned and paid prior to the applicable date, in each case provided there were no arrearages in the minimum quarterly distribution on our common units at that time. On May 16, 2014, 2,240,000 subordinated units converted on a one-for-one basis into common units pursuant to the terms of our partnership agreement. The remaining 4,480,000 subordinated units converted on a one-for-one basis into common units pursuant to the terms of our partnership agreement on February 13, 2015.

During Subordination Period. Assuming our general partner had, and maintained, an approximate 0.1% general partner interest in us, our partnership agreement required us to distribute all of our available cash from operating surplus for each quarter in the following manner during the subordination period:

- first, 99.9% to the common unitholders, pro rata, and 0.1% to our general partner, until we distributed for each common unit an amount equal to the minimum quarterly distribution for that quarter;

- second, 99.9% to the common unitholders, pro rata, and 0.1% to our general partner, until we distributed for each common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;

- third, 99.9% to the subordinated unitholders, pro rata, and 0.1% to our general partner, until we distributed for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and

- fourth, 99.9% to all unitholders pro rata, and 0.1% to our general partner, until each unitholder received a total of $0.54625 per unit for that quarter.

If cash distributions to our unitholders exceed $0.54625 per unit in any quarter, our unitholders and our general partner will receive distributions according to the following percentage allocations:

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Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions Unitholders	General Partner
above $0.54625 up to $0.59375	86.9%	13.1%
above $0.59375	76.9%	23.1%

The percentage interests shown for our general partner include an approximate 0.1% general partner interest. We refer to the additional increasing distributions to our general partner in excess of its general partner interest as incentive distributions.

After Subordination Period. Our partnership agreement requires us to distribute all of our available cash from operating surplus each quarter in the following manner after the subordination period:

- first, 99.9% to the common unitholders, pro rata, and 0.1% to our general partner, until we distribute for each common unit an amount equal to the minimum quarterly distribution for that quarter;
- second, 99.9% to all unitholders, pro rata, and 0.1% to our general partner, until each unitholder receives a total of $0.54625 per unit for that quarter; and
- thereafter, as provided in the table above.

Securities Authorized for Issuance under Equity Compensation Plans

See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters for information regarding our equity compensation plans as of December 31, 2014.

Unregistered Sales of Equity Securities

None not previously reported on a Current Report on Form 8-K.

Issuer Purchaser of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA.

The selected consolidated financial data presented as of December 31, 2014, 2013, 2012 and 2011 and for the years ended December 31, 2014, 2013, 2012 and for the period from November 16 to December 31, 2011 are derived from our audited financial statements. The selected financial data for the period from January 1 to November 15, 2011 and as of and for the year ended December 31, 2010 are derived from the audited financial statements of our predecessor. The selected financial data should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data, both contained herein. The following table shows selected financial data of the Partnership and our predecessor for the periods and as of the dates indicated.

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(in thousands)	Partnership Year Ended December 31, 2014	Year Ended December 31, 2013	Year Ended December 31, 2012	November 16 to December 31, 2011	Predecessor January 1 to November 15, 2011	Year Ended December 31, 2010
Statement of Operations Data:						
Revenues:						
Oil sales	$ 76,662	$ 77,181	$ 72,916	$ 9,766	$ 59,605	$ 52,670
Natural gas sales	28,521	26,800	23,502	3,976	35,883	48,088
Natural gas liquids sales	11,362	10,147	11,627	1,976	14,500	14,748
Gain (loss) on commodity derivative instruments, net	71,235	781	12,748	12,287	22,027	24,065
Other income	125	186	45		159	116
Total revenues	187,905	115,095	120,838	28,005	132,174	139,687
Operating expenses:						
Lease operating expenses	25,821	25,397	29,069	3,193	21,391	23,804
Production and ad valorem taxes	8,738	8,614	7,790	1,076	7,763	9,320
Depletion and depreciation	36,729	43,420	46,928	5,876	37,206	55,828
Impairment of oil and gas properties	37,758	63,663	3,544		16,765	11,712
Accretion expense	2,071	1,924	1,575	191	1,290	1,366
Loss (gain) on settlement of asset retirement obligations	151	358	(31)		496	(209)
Management fees					5,435	6,104
General and administrative expenses	11,447	11,965	13,758	1,892	5,149	5,293
Total operating expenses	122,715	155,341	102,633	12,228	95,495	113,218
Operating income (loss)	65,190	(40,246)	18,205	15,777	36,679	26,469
Other income (expense), net						
Interest income					1	17
Interest expense	(10,472)	(9,235)	(6,596)	(604)	(919)	(3,223)
Gain (loss) on interest rate derivative instruments, net	(1,790)	1,256	(4,650)		(133)	(897)
Other income (expense), net	(12,262)	(7,979)	(11,246)	(604)	(1,051)	(4,103)
Income (loss) before taxes	52,928	(48,225)	6,959	15,173	35,628	22,366
Income tax expense	(186)	(56)	(172)	(48)	76	(32)
Net income (loss)	$ 52,742	$ (48,281)	$ 6,787	$ 15,125	$ 35,704	$ 22,334
Net (income) loss attributable to common control operations		(448)	(6,790)	(2,975)		
Net income (loss) available to unitholders	$ 52,742	$ (48,729)	$ (3)	$ 12,150		
General partner s interest in net income (loss)	$ 53	$ (49)	$	$ 12		
Limited partners interest in net income (loss)	$ 52,689	$ (48,680)	$ (3)	$ 12,138		
Net income (loss) per limited partner unit (basic and diluted)	$ 1.94	$ (1.92)	$ (0.00)	$ 0.54		

Weighted average number of limited partner units outstanding (basic and diluted)		27,092		25,372		22,425		22,418				
Other Financial Data:												
Adjusted EBITDA	$	83,385	$	79,550	$	81,156	$	13,603	$	79,762	$	119,130
Cash Flow Data:												
Net cash provided by (used in) operating activities	$	67,885	$	65,541	$	77,223	$	5,523	$	84,027	$	121,269
Net cash provided by (used in) investing activities	$	(69,950)	$	(35,805)	$	(40,433)	$	(755)	$	(44,891)	$	(125,846)
Net cash provided by (used in) financing activities	$	1,224	$	(28,786)	$	(34,836)	$	(3,255)	$	(38,000)	$	1,505

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	Partnership				Predecessor	
(in thousands)	Year Ended December 31, 2014	Year Ended December 31, 2013	Year Ended December 31, 2012	November 16 to December 31, 2011	January 1 to November 15, 2011	Year Ended December 31, 2010
Balance Sheet Data:						
Working capital	$ 49,531	$ 17,131	$ 19,366	$ 23,124	$ (1)	$ 33,209
Total assets	$ 558,954	$ 488,350	$ 565,470	$ 579,934	$ (1)	$ 504,622
Total debt	$ 280,000	$ 250,000	$ 228,000	$ 155,800	$ (1)	$ 27,251
Unitholders equity/partners capital	$ 218,637	$ 192,258	$ 290,776	$ 390,150	$ (1)	$ 426,733

(1) These balance sheet amounts are not presented as they were not previously included in our predecessor s financial statements included in Item 8. Financial Statements and Supplementary Data.

Non-GAAP Financial Measures

Below we disclose the non-GAAP financial measures Adjusted EBITDA and Distributable Cash Flow for the periods presented and provide reconciliations of these items to net income (loss), our most directly comparable financial performance measure calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income (loss) plus or minus:

- Income tax expense;
- Interest expense-net, including loss (gain) on interest rate derivative instruments, net;
- Depletion and depreciation;
- Accretion of asset retirement obligations;
- Amortization of equity awards;
- Loss (gain) on settlement of asset retirement obligations;
- Loss (gain) on commodity derivative instruments, net;
- Commodity derivative instrument net cash settlements;
- Impairment of oil and natural gas properties; and
- Other non-recurring items that we deem appropriate.

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our financial performance as compared to that of other companies and partnerships in our industry, without regard to financing methods, capital structure or historical cost basis.

We define Distributable Cash Flow as Adjusted EBITDA less cash income tax expense, cash interest expense and estimated maintenance capital.

Distributable Cash Flow is a supplemental financial measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us (prior to the establishment of any retained cash reserve by our general partner) to the cash distributions we expect to pay our unitholders. Distributable Cash Flow is also an important financial measure for our unitholders as it serves as an indicator of our success in providing a cash return on investment. Specifically, distributable cash flow indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable Cash Flow is a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the yield is based on the amount of cash distributions the entity pays to a unitholder compared to the unit price.

Our management believes that both Adjusted EBITDA and Distributable Cash Flow are useful to investors because these measures are used by many partnerships in the industry as measures of operating and financial performance and are commonly employed by financial analysts and others to evaluate the operating and financial performance from period to period and to compare it with the performance of other publicly traded partnerships

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within the industry. Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income (loss), operating income (loss), or any other measures of financial performance presented in accordance with GAAP. Our Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA and Distributable Cash Flow in the same manner.

Our Adjusted EBITDA for the years ended December 31, 2014, 2013, 2012, and for the period from November 16 to December 31, 2011 was $83.4 million, $79.6 million, $81.2 million, and $13.6 million, respectively. Our predecessor s Adjusted EBITDA for the period from January 1 to November 15, 2011 and the year ended December 31, 2010 was $79.8 million and $119.1 million, respectively.

Our Distributable Cash Flow for the years ended December 31, 2014, 2013, and 2012 and for the period from November 16 to December 31, 2011 was $52.0 million, $49.6 million, $53.8 million and $11.0 million, respectively.

Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Income (Loss)

The following table presents a reconciliation of Adjusted EBITDA and Distributable Cash Flow to net income (loss), our most directly comparable GAAP financial performance measure, for each of the periods indicated.

	Partnership				Predecessor	
(in thousands)	**Year Ended December 31, 2014**	**Year Ended December 31, 2013**	**Year Ended December 31, 2012**	**November 16 to December 31, 2011**	**January 1 to November 15, 2011**	**Year Ended December 31, 2010**
Net income (loss)	$ 52,742	$ (48,281)	$ 6,787	$ 15,125	$ 35,704	$ 22,334
Income tax expense	186	56	172	48	(76)	32
Interest expense-net, including loss (gain) on interest rate derivative instruments, net	12,262	7,979	11,246	604	1,052	4,120
Depletion and depreciation	36,729	43,420	46,928	5,876	37,206	55,828
Accretion of asset retirement Obligations	2,071	1,924	1,575	191	1,290	1,366
Amortization of equity awards	1,081	549	313	31		
Loss (gain) on settlement of asset retirement obligations	151	358	(31)		496	(209)
Loss (gain) on commodity derivative instruments, net	(71,235)	(781)	(12,748)	(12,287)	(22,027)	(24,065)
Commodity derivative instrument net cash Settlements	11,640	10,663	23,370	4,015	9,353	48,029
Impairment of oil and natural gas properties	37,758	63,663	3,544		16,765	11,712
Interest income					(1)	(17)
Adjusted EBITDA	$ 83,385	$ 79,550	$ 81,156	$ 13,603	$ 79,762	$ 119,130

Adjusted EBITDA	$ 83,385	$ 79,550	$ 81,156	$ 13,603
Cash income tax expense	(146)	(132)	(86)	
Cash interest expense	(10,905)	(9,513)	(7,012)	(31)
Estimated maintenance capital (1)	(20,300)	(20,300)	(20,300)	(2,538)
Distributable cash flow	$ 52,034	$ 49,605	$ 53,758	$ 11,034

(1) Estimated maintenance capital expenditures as defined by our partnership agreement represent our estimate of the amount of capital required on average per year to maintain our production over the long term. For the period from November 16 to December 31, 2011, the amount represents prorated maintenance capital for the period.

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

Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the financial statements and related notes contained in Item 8. Financial Statements and Supplementary Data. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. These forward-looking statements are subject to events, risks,

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assumptions and uncertainties that may be outside our control, including, among other things, the risk factors discussed in Item 1A of this Annual Report. Our actual results could differ materially from those discussed in these forward-looking statements. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See Cautionary Statement Regarding Forward-Looking Information in the front of this Annual Report.

Overview

LRR Energy, L.P. (we, us, our, or the Partnership) is a Delaware limited partnership formed in April 2011 by Lime Rock Management LP (Li Rock Management), an affiliate of Lime Rock Resources A, L.P. (LRR A), Lime Rock Resources B, L.P. (LRR B) and Lime Rock Resources C, L.P. (LRR C), to operate, acquire, exploit and develop producing oil and natural gas properties in North America with long-lived, predictable production profiles. LRR A, LRR B and LRR C were formed by Lime Rock Management in July 2005 for the purpose of acquiring mature, low-risk producing oil and natural gas properties with long-lived production profiles. As used herein, references to Fund I refer collectively to LRR A, LRR B and LRR C; references to Fund II refer collectively to Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P.; and references to Fund III refer collectively to Lime Rock Resources III-A, L.P. and Lime Rock Resources III-C, L.P. References to Lime Rock Resources refer collectively to Fund I, Fund II, and Fund III.

Our properties are located in the Permian Basin region in West Texas and Southeast New Mexico, the Mid-Continent region in Oklahoma and East Texas and the Gulf Coast region in Texas. These properties consist of working interests in 856 gross (745 net) producing wells, of which we owned a 87% average working interest. As of December 31, 2014, our total estimated proved reserves were 33.8 MMBoe, of which 52% were oil and NGLs as measured by volume, 73% were proved developed producing and 15% were proved developed non-producing. As of December 31, 2014, our estimated proved reserves had a standardized measure of $441.7 million.

Of our total estimated proved reserves as of December 31, 2014, 16.3 MMBoe, or 48%, are located in the Permian Basin region; 14.2 MMBoe, or 42%, are located in the Mid-Continent region; and 3.3 MMBoe, or 10%, are located in the Gulf Coast region.

Acquisition of Properties

On June 1, 2012, we completed an acquisition from Fund I of certain oil and natural gas properties located in the Permian Basin region of New Mexico and onshore Gulf Coast region of Texas for $65.1 million in cash consideration (the June 2012 Acquisition). The June 2012 Acquisition was effective as of March 1, 2012. In September 2012, we received $1.1 million in cash from Fund I related to post-closing adjustments to the purchase price.

On January 3, 2013, we completed an acquisition from Fund I of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma for a purchase price of $21.0 million (the January 2013 Acquisition). In addition, as part of the January 2013 Acquisition, we acquired commodity hedge contracts valued at approximately $1.7 million at the closing of the January 2013 Acquisition. The January 2013 Acquisition was effective October 1, 2012. In June 2013, we paid $0.4 million in cash to Fund I related to post-closing adjustments to the purchase price.

On April 1, 2013, we completed an acquisition of certain oil and natural gas properties located in the Mid-Continent region in Oklahoma and crude oil hedges from Fund II for a purchase price of $38.2 million (the April 2013 Acquisition). As part of the April 2013 Acquisition, we acquired crude oil hedges valued at approximately $0.4 million as of the closing of the April 2013 Acquisition. The April 2013 Acquisition was effective April 1, 2013.

On October 1, 2014, we completed an acquisition of oil and natural gas properties in the Stroud field located in Lincoln and Creek Counties, Oklahoma for a purchase price of $38.0 million (the October 2014 Acquisition) from an unrelated third party. The October 2014 Acquisition was effective September 1, 2014. We financed the acquisition with borrowings under our Credit Agreement. In January 2015, we paid $0.2 million in cash to the seller related to post-closing adjustments to the purchase price.

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How We Conduct Our Business and Evaluate Our Operations

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

- oil, NGLs and natural gas production volumes;
- realized prices on the sale of oil, NGLs and natural gas, including the effect of our commodity derivative contracts;
- lease operating expenses;
- production and ad valorem taxes;
- general and administrative expenses;
- Adjusted EBITDA; and
- Distributable Cash Flow.

Production Volumes

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

Realized Prices on the Sale of Oil, NGLs and Natural Gas

Factors Affecting the Sales Price of Oil, NGLs and Natural Gas. We market our oil, NGLs and natural gas production to a variety of purchasers based on regional pricing. The relative prices of oil, NGLs and natural gas are determined by the factors impacting global and regional supply and demand dynamics, such as economic conditions, production levels, weather cycles and other events. In addition, relative prices are heavily influenced by product quality and location relative to consuming and refining markets.

Oil Prices. 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 oils differ from one another in their molecular makeup, which plays an important part in their refining and subsequent sale as petroleum products. Among other things, there are two characteristics that commonly drive quality differentials: (1) the oil s American Petroleum Institute (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 (sweet oil) is less expensive to refine and, as a result, normally sells at a higher price than high sulfur-content oil (sour oil).

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

The oil produced from our properties is a combination of sweet and sour oil, varying by location. We sell our oil at the NYMEX-WTI price, which is adjusted for quality and transportation differentials, depending primarily on location and purchaser. The differential varies, but our oil normally sells at a discount to the NYMEX-WTI price.

Natural Gas Prices. The NYMEX-Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX-Henry Hub price as a result of quality and location differentials. Quality differentials to NYMEX-Henry Hub prices result from: (1) the Btu content of natural gas, which measures its heating value, and (2) the percentage of sulfur, CO2 and other inert content by volume. Wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGLs. Natural gas with low sulfur and CO2 content sells at a premium to natural gas with high sulfur and CO2 content because of the added cost to separate the sulfur and CO_2 from the natural gas to render it marketable. The wet natural gas is processed in third-party natural gas plants and residue natural gas as well as NGLs are recovered and sold. The dry natural gas residue from our properties is generally sold based on index prices in the region from which it is produced.

Location differentials to NYMEX-Henry Hub prices result from variances in transportation costs based on the natural gas proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant, which is generally in the form of percentage of proceeds. The differential varies, but our natural gas normally sells at a discount to the NYMEX-Henry Hub price.

NGL Prices. Gas produced from a well that is fused with NGLs is referred to as wet gas. Wet gas is generally sold at the wellhead or transported to a gas processing plant where the NGLs are separated from the wet gas, leaving NGL component products and dry gas residue. Both the NGLs and dry gas residue are transported from or sold at a gas processing plant s tailgate. The NGLs recovered from the processing of our wet gas are sold as blended NGL barrels at a Mont Belvieu or Conway posted price, which is representative of the weighted average market value of the five primary NGL component products. For the majority of the properties that we operate that produce wet gas, we have agreements in place with gas plants in the various regions to process this natural gas in order to receive the revenue benefit of the NGLs that are generated from processing.

In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2014, the NYMEX-WTI oil price ranged from a high of $107.62 per Bbl to a low of $53.27 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $7.92 per MMBtu to a low of $2.75 per MMBtu. For the five years ended December 31, 2014, the NYMEX-WTI oil price ranged from a high of $113.93 per Bbl to a low of $53.27 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $7.92 per MMBtu to a low of $1.82 per MMBtu. As of February 27, 2015, the NYMEX-WTI oil spot price was $49.76 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.75 per MMBtu.

Commodity Derivative Contracts. We enter into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Our strategy includes entering into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 65% to 85% of our estimated production from total proved developed producing reserves over a three-to-five year period at a given point of time, although we may from time to time hedge more or less than this approximate range.

For a summary of volumes of our production covered by commodity derivative contracts and the average prices at which the production is hedged as of December 31, 2014, please refer to Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Lease Operating Expenses

We strive to increase our production levels to maximize our revenue and cash available for distribution. 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 or production and other 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.

A majority of our lease operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. As these costs are driven not only by volumes of oil, NGLs and natural gas produced but also volumes of water produced, fields that have a high percentage of water production relative to oil, NGLs and natural gas production, also known as a high water cut, will experience higher levels of costs for each Bbl of oil or NGL or Mcf of natural gas produced.

We monitor our operations to ensure that we are incurring operating costs at the optimal level. Accordingly, we monitor our production expenses and operating costs per well to determine if any wells or properties should be shut in, recompleted or sold. We typically evaluate our oil, NGL and natural gas operating costs on a per Boe basis. This

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unit rate allows us to monitor these costs in certain fields and geographic areas to identify trends and to benchmark against other producers.

Production and Ad Valorem Taxes

The various states in which we operate regulate the development, production, gathering and sale of oil and natural gas, including imposing production taxes and requirements for obtaining drilling permits. Ad valorem taxes are generally tied to the valuation of the oil and natural gas properties; however, these valuations are reasonably correlated to revenues, excluding the effects of any commodity derivative contracts.

General and Administrative Expenses

We have entered into a services agreement with Lime Rock Management and Lime Rock Resources Operating Company, Inc. (ServCo) pursuant to which management, administrative and operating services are provided to our general partner and us to manage and operate our business. Our general partner reimburses Lime Rock Management and ServCo for all costs and services they incur on our general partner s and our behalf. Under the services agreement, our general partner will reimburse each of Lime Rock Management and ServCo, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. For further information regarding the services agreement, please read Item 13. Certain Relationships and Related Transactions, and Director Independence Services Agreement.

Adjusted EBITDA and Distributable Cash Flow

Our management believes that both Adjusted EBITDA and Distributable Cash Flow are useful to investors because these measures are used by many partnerships in the industry as measures of operating and financial performance and are commonly employed by financial analysts and others to evaluate the operating and financial performance from period to period and to compare it with the performance of other publicly traded partnerships within the industry. Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income (loss), operating income (loss), or any other measures of financial performance presented in accordance with GAAP. Our Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA and Distributable Cash Flow in the same manner. For further discussion of these non-GAAP financial measures, please read Item 6. Selected Financial Data Non-GAAP Financial Measures.

Trends and 2015 Outlook

Commodity prices have declined significantly since November 2014. We anticipate a sustained depressed commodity pricing environment to have a significant adverse impact on our business. Although current capital markets are challenging, they are accessible. We cannot accurately predict future commodity prices nor when or whether capital markets will improve. Lower commodity prices may impact our financial results through impairments of our oil and natural gas properties, reductions in our borrowing base and reductions in our distributions.

Lower commodity prices caused us to significantly reduce our 2015 capital budget compared to 2014. We expect to spend approximately $19.0 million of total capital expenditures on the development of our oil and natural gas properties in 2015. Our 2015 budget consists entirely of maintenance capital expenditures. The estimated capital expenditures for 2015 do not include any amounts for acquisitions of oil and natural gas properties. We may reduce our capital expenditure budget if commodity prices remain depressed for a prolonged period or commodity prices further significantly decline.

The estimate of total capital expenditures provided above sets forth management s best estimate based on current and anticipated market conditions and is based on current expectations as to the level of capital expenditures, which in turn depends on the amount of oil, natural gas and NGLs we produce, oil, natural gas and NGL prices, the prices at which we sell our oil, natural gas and NGL production, the level of our operating costs and the prices at which we enter into commodity derivative contracts.

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Our revenues, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices historically have been volatile and are expected to be volatile in the future. Factors affecting the price of oil include worldwide economic conditions, geopolitical activities, worldwide supply disruptions, weather conditions, actions taken by the Organization of Petroleum Exporting Countries and the value of the U.S. dollar in international currency markets. Factors affecting the price of natural gas include the discovery of substantial accumulations of natural gas in unconventional reservoirs due to technological advancements necessary to commercially produce these unconventional reserves, North American weather conditions, industrial and consumer demand for natural gas, storage levels of natural gas and the availability and accessibility of natural gas deposits in North America. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. Please read Item 1A. Risk Factors.

In order to mitigate the impact of changes in oil and natural gas prices on our cash flows, we have entered into commodity derivative contracts, and we intend to enter into commodity derivative contracts in the future, to reduce cash flow volatility. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk for a summary of volumes of our production covered by commodity derivative contracts and the average prices at which the production is hedged through 2018.

As an oil and natural gas company, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. Our future growth will depend on our ability to continue to add estimated reserves in excess of our production. We plan to maintain our focus on adding reserves through acquisitions and exploitation projects and improving the economics of producing oil and natural gas from our existing fields in lieu of higher-risk exploration projects. We expect that these acquisition opportunities may come from Lime Rock Resources and possibly from Lime Rock Partners and its affiliates and also from unrelated third parties. Our ability to add proved reserves through acquisitions and exploitation projects is dependent upon many factors, including our ability to successfully identify and close acquisitions, raise capital, obtain regulatory approvals and procure contract drilling rigs and personnel.

Financial and Operating Data

	Year Ended December 31,		
	2014	2013	2012
Revenues (in thousands):			
Oil sales	$ 76,662	$ 77,181	$ 72,916
Natural gas sales	28,521	26,800	23,502
Natural gas liquids sales	11,362	10,147	11,627
Gain (loss) on commodity derivative instruments, net	71,235	781	12,748
Other income	125	186	45
Total revenues	187,905	115,095	120,838
Expenses (in thousands):			
Lease operating expense	$ 25,821	$ 25,397	$ 29,069
Production and ad valorem taxes	8,738	8,614	7,790
Depletion and depreciation	36,729	43,420	46,928
Impairment of oil and natural gas properties	37,758	63,663	3,544
General and administrative expense	11,447	11,965	13,758
Interest expense	10,472	9,235	6,596
Loss (gain) on interest rate derivative instruments, net	1,790	(1,256)	4,650
Production: (1)			

Oil (MBbls)	904	837	834
Natural gas (MMcf)	6,467	7,246	8,487
NGLs (MBbls)	366	315	311
Total (MBoe)	2,348	2,360	2,560
Average net production (Boe/d)	6,433	6,466	6,995

(1) The Red Lake area constituted approximately 30% of our estimated proved reserves as of December 31, 2014. The Potato Hills field constituted approximately 20% of our estimated proved reserves as of December 31, 2014. The following table is a summary of production by product for the Red Lake and Potato Hills fields for the years indicated:

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	Year Ended December 31, 2014	2013	2012
Red Lake field:			
Oil (MBbls)	535	482	432
Natural gas (MMcf)	869	793	701
NGLs (MBbls)	228	189	158
Total (MBoe)	908	803	707
Potato Hills field:			
Oil (MBbls)			
Natural gas (MMcf)	2,480	2,828	3,188
NGLs (MBbls)			
Total (MBoe)	413	471	531

	Year Ended December 31, 2014	2013	2012
Average sales price:			
Oil (per Bbl):			
Sales price	$ 84.80	$ 92.21	$ 87.43
Effect of settled commodity derivative instruments (1)	5.10	(2.45)	4.38
Realized sales price	$ 89.90	$ 89.76	$ 91.81
Natural gas (per Mcf):			
Sales price	$ 4.41	$ 3.70	$ 2.77
Effect of settled commodity derivative instruments(1)	0.97	1.44	2.13
Realized sales price	$ 5.38	$ 5.14	$ 4.90
NGLs (per Bbl):			
Sales price	$ 31.04	$ 32.21	$ 37.39
Effect of settled commodity derivative instruments(1)	0.11	4.08	5.22
Realized sales price	$ 31.15	$ 36.29	$ 42.61
Average unit costs per Boe:			
Lease operating expenses	$ 11.00	$ 10.76	$ 11.36
Production and ad valorem taxes	$ 3.72	$ 3.65	$ 3.04
Depletion and depreciation	$ 15.64	$ 18.40	$ 18.33
General and administrative expenses	$ 4.88	$ 5.07	$ 5.38

(1) The dollar per Boe impact of commodity derivative instruments settlements on our realized sales prices was $4.66, $4.09, and $9.12 per Boe for the years ended December 31, 2014, 2013 and 2012, respectively.

Results of Operations

Our Results for the Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

We recorded net income of $52.7 million for the year ended December 31, 2014 compared to net loss of $48.3 million for the year ended December 31, 2013, primarily related to gains on commodity derivative instruments during the year ended December 31, 2014. The following discussion summarizes key components of the changes between periods.

Sales Revenues. A summary of increases (decreases) in our oil, natural gas and NGL revenues between the year ended December 31, 2013 and December 31, 2014 follows in (thousands):

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Oil, natural gas and NGL revenues-prior period	$	114,128
Increase (decrease)		
Price realization		
Oil		(6,202)
Natural gas		5,158
NGLs		(369)
Sales volumes		
Oil		5,682
Natural gas		(3,435)
NGLs		1,583
Oil, natural gas and NGL revenues-current period	$	116,545

Sales revenues increased from $114.1 million for the year ended December 31, 2013 to $116.5 million for the year ended December 31, 2014, primarily driven by higher natural gas realizations and oil and NGL production offset by lower oil realizations and natural gas production. Sales revenues for the year ended December 31, 2014 consisted of oil sales of $76.7 million, natural gas sales of $28.5 million and NGL sales of $11.3 million. Sales revenues for the year ended December 31, 2013 consisted of oil sales of $77.2 million, natural gas sales of $26.8 million and NGL sales of $10.1 million.

Our production volumes for the year ended December 31, 2014 included 1,270 MBbls of oil and NGLs and 6,467 MMcf of natural gas, or 3,479 Bbl/d of oil and NGLs and 17,718 Mcf/d of natural gas. On an equivalent basis, production for the period was 2,348 MBoe, or 6,433 Boe/d. Our production volumes for the year ended December 31, 2013 included 1,152 MBbls of oil and NGLs and 7,246 MMcf of natural gas, or 3,156 Bbl/d of oil and NGLs and 19,852 Mcf/d of natural gas. On an equivalent basis, production for the period was 2,360 MBoe, or 6,466 Boe/d. The increase in oil and NGL sales volumes was primarily driven by the continued drilling at our Red Lake field. Given our focus on drilling at the Red Lake field, the production at our natural gas properties has decreased due to the natural decline of the wells.

Our average sales price per Bbl for oil and NGLs for the year ended December 31, 2014, excluding the effect of commodity derivative contracts, was $84.80 and $31.04, respectively. Our average sales price per Mcf of natural gas for the year ended December 31, 2014, excluding the effect of commodity derivative contracts, was $4.41. Our average sales price per Bbl for oil and NGLs for the year ended December 31, 2013, excluding the effect of commodity derivative contracts, was $92.21 and $32.21, respectively. Our average sales price per Mcf of natural gas for the year ended December 31, 2013, excluding the effect of commodity derivative contracts, was $3.70.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, we recorded a net gain from our commodity hedging program for the year ended December 31, 2014 of $71.2 million, which is comprised of a positive net cash settlements and amortization of approximately $10.9 million and gains in fair value of derivatives of approximately $60.3 million. For the year ended December 31, 2013, we recorded a net gain from our commodity hedging program of $0.8 million, which is comprised of a positive net cash settlements and amortization of approximately $9.7 million and declines in fair value of derivatives of approximately $8.9 million. Lower commodity prices during the year lead to the significant impact on our gain on commodity derivative contracts for the year ended December 31, 2014.

Lease Operating Expense. Our lease operating expenses were $25.8 million, or $11.00 per Boe, for the year ended December 31, 2014 compared to $25.4 million, or $10.76 per Boe, for the year ended December 31, 2013. The primary driver of the increased lease operating expenses were as a result of the Stroud Acquisition in the fourth quarter of 2014.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were $8.7 million, or $3.72 per Boe, for the year ended December 31, 2014 compared to $8.6 million, or $3.65 per Boe, for the year ended December 31, 2013. Production taxes accounted for approximately $8.2 million and ad valorem taxes for approximately $0.5 million of the total taxes recorded during the year ended December 31, 2014. Production taxes accounted for approximately $8.0 million and ad valorem taxes for approximately $0.6 million of the total taxes recorded during the year ended December 31, 2013.

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Impairment of Oil and Natural Gas Properties. We recorded an impairment of $37.8 million on our proved properties for the year ended December 31, 2014 in the Permian Basin and Mid-Continent regions. The impairment was primarily due to lower estimated future net realizable commodity prices and reclassifications. We recorded an impairment of $63.7 million on our proved properties for the year ended December 31, 2013 in the Permian Basin and Gulf Coast regions. The impairment was primarily due to lower estimated future net realizable oil and natural gas liquid prices and reserve category reclassifications. These impairments had no impact on our cash flows, liquidity position, or debt covenants.

If future oil or natural gas prices or our reserves decline further, the estimated undiscounted future cash flows for the proved oil and natural gas properties may not exceed the net capitalized costs for such properties and a non-cash impairment charge may be required to be recognized in future periods. As of February 27, 2015, the NYMEX-WTI oil spot price was $49.76 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.75 per MMBtu.

General and Administrative Expenses. Our general and administrative expenses were $11.4 million, or $4.88 per Boe, for the year ended December 31, 2014 compared to $12.0 million, or $5.07 per Boe, for the year ended December 31, 2013.

Interest Expense. Our interest expense is comprised of interest on our credit facility and term loan and amortization of debt issuance costs. Interest expense was $10.5 million and $9.2 million for the year ended December 31, 2014 and 2013, respectively. The increase in interest expense was primarily due to the increased debt level outstanding during the year ended December 31, 2014.

Effects of Interest Rate Derivatives. Gain (loss) on interest rate derivative contracts, net, was a $1.8 million loss for the year ended December 31, 2014, including $0.9 million in negative cash settlements and $0.9 million in negative fluctuations in the fair value of derivatives. Gain (loss) on interest rate derivative contracts, net, was a $1.3 million gain for the year ended December 31, 2013, including $0.7 million in negative settlements and $2.0 million in positive fluctuations in the fair value of derivatives.

Our Results for the Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

We recorded net loss of $48.3 million for the year ended December 31, 2013 compared to net income of $6.8 million for the year ended December 31, 2012, primarily related to a non-cash impairment charge of $63.7 million recorded during the year ended December 31, 2013. The following discussion summarizes key components of the changes between periods.

Sales Revenues. A summary of increases (decreases) in our oil, natural gas and NGL revenues between the year ended December 31, 2012 and December 31, 2013 follows (thousands):

Oil, natural gas and NGL revenues-prior period	$	108,045
Increase (decrease)		
Price realization		
Oil		3,987
Natural gas		7,893

NGLs		(1,611)
Sales volumes		
Oil		277
Natural gas		(4,592)
NGLs		129
Oil, natural gas and NGL revenues-current period	$	114,128

Sales revenues increased from $108.0 million for the year ended December 31, 2012 to $114.1 million for the year ended December 31, 2013, primarily driven by higher oil and natural gas price realizations offset by lower natural gas production. Sales revenues for the year ended December 31, 2013 consisted of oil sales of $77.2 million, natural gas sales of $26.8 million and NGL sales of $10.1 million. Sales revenues for the year ended December 31, 2012 consisted of oil sales of $72.9 million, natural gas sales of $23.5 million and NGL sales of $11.6 million.

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Our production volumes for the year ended December 31, 2013 included 1,152 MBbls of oil and NGLs and 7,246 MMcf of natural gas, or 3,156 Bbl/d of oil and NGLs and 19,852 Mcf/d of natural gas. On an equivalent basis, production for the period was 2,360 MBoe, or 6,466 Boe/d. Our production volumes for the year ended December 31, 2012 included 1,145 MBbls of oil and NGLs and 8,487 MMcf of natural gas, or 3,128 Bbl/d of oil and NGLs and 23,189 Mcf/d of natural gas. On an equivalent basis, production for the period was 2,560 MBoe, or 6,995 Boe/d. Our natural gas production declined during the year ended December 31, 2013 due to the natural production decline of our natural gas reserves, well downtime, flaring and the issues at our Pecos Slope field as discussed below.

At our Red Lake field, our third party gas processor required us to flare approximately 73 Boe/d due to plant capacity constraints and compressor issues during the year ended December 31, 2013. A new compressor station at the plant was put into service in the fourth quarter of 2013.

Our Pecos Slope field production was curtailed by approximately 1.2 MMcf/d (200 Boe/d) during the year ended December 31, 2013 due to the previously disclosed high nitrogen content of our produced natural gas. Severe winter weather did not have a material impact on our production for the year ended December 31, 2013.

Our average sales price per Bbl for oil and NGLs for the year ended December 31, 2013, excluding the effect of commodity derivative contracts, was $92.21 and $32.21, respectively. Our average sales price per Mcf of natural gas for the year ended December 31, 2013, excluding the effect of commodity derivative contracts, was $3.70. Our average sales price per Bbl for oil and NGLs for the year ended December 31, 2012, excluding the effect of commodity derivative contracts, was $87.43 and $37.39, respectively. Our average sales price per Mcf of natural gas for the year ended December 31, 2012, excluding the effect of commodity derivative contracts, was $2.77.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, we recorded a net gain from our commodity hedging program for the year ended December 31, 2013 of $0.8 million, which is comprised of a positive settlements and amortization of purchases of $9.7 million and declines in fair value of derivatives of $8.9 million. For the year ended December 31, 2012, we recorded a net gain from our commodity hedging program of $12.7 million, which is comprised of positive settlements and amortization of $23.3 million and declines in fair value of derivatives of $10.6 million. Volatility in commodity prices has a significant impact on our gains and losses on commodity derivative contracts.

Lease Operating Expense. Our lease operating expenses were $25.4 million, or $10.76 per Boe, for the year ended December 31, 2013 compared to $29.1 million, or $11.36 per Boe, for the year ended December 31, 2012. The primary drivers of the decreased lease operating expenses were lower workover expenses and lower saltwater disposal costs in 2013.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were $8.6 million, or $3.65 per Boe, for the year ended December 31, 2013 compared to $7.8 million, or $3.04 per Boe, for the year ended December 31, 2012. Production taxes accounted for $8.0 million and ad valorem taxes for $0.6 million of the total taxes recorded during the year ended December 31, 2013. Production taxes accounted for $7.1 million and ad valorem taxes for $0.7 million of the total taxes recorded during the year ended December 31, 2012.

Depletion and Depreciation. Our depletion and depreciation expense was $43.4 million, or $18.40 per Boe, for the year ended December 31, 2013 compared to $46.9 million, or $18.33 per Boe, for the year ended December 31, 2012. The decrease in the depreciation expense was primarily related to lower production volumes.

Impairment of Oil and Natural Gas Properties. We recorded an impairment of $63.7 million on our proved properties for the year ended December 31, 2013 in the Permian Basin and Gulf Coast regions. The impairment was primarily due to lower estimated future net realizable oil and natural gas liquid prices and reserve category reclassifications. We recorded an impairment of $3.5 million for the year ended December 31, 2012. Of this amount, $3.1 million related to a decline in natural gas prices that impacted our proved properties during the first quarter of 2012 and $0.4 million related to impairments of unproved properties in the third quarter of 2012. These impairments had no impact on our cash flows, liquidity position, or debt covenants.

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If future oil or natural gas prices or if our reserves decline further, the estimated undiscounted future cash flows for the proved oil and natural gas properties may not exceed the net capitalized costs for such properties and a non-cash impairment charge may be required to be recognized in future periods.

General and Administrative Expenses. Our general and administrative expense was $12.0 million, or $5.07 per Boe, for the year ended December 31, 2013 compared to $13.8 million, or $5.38 per Boe, for the year ended December 31, 2012. The decrease was primarily due to lower consulting and allocated expenses in 2013.

Interest Expense. Our interest expense is comprised of interest on our credit facility and term loan and amortization of debt issuance costs. Interest expense was $9.2 million and $6.6 million for the year ended December 31, 2013 and 2012, respectively. The increase in interest expense was primarily due to the increased debt level outstanding during the year ended December 31, 2013.

Effects of Interest Rate Derivatives. Gains on interest rate derivative contracts, net, were $1.3 million for the year ended December 31, 2013, including $0.7 million in negative settlements and $2.0 million in positive fluctuations in the fair value of derivatives. Losses on interest rate derivative contracts, net, were $4.7 million for the year ended December 31, 2012, including $0.5 million in negative settlements and $4.2 million in declines in the fair value of derivative instruments.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness, to meet our collateral requirements or to pay our distributions depends on our ability to generate cash. 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, weather and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

Our primary sources of liquidity and capital resources are cash flows generated by operating activities, borrowings under our credit facility and equity offerings under our at-the-market offering program (the ATM Program), described below. We may issue additional equity and debt as needed.

In February 2014, we launched the ATM Program with MLV & Co. LLC (MLV) as sales agent. We may sell from time to time through MLV our common units representing limited partner interests having an aggregate offering amount of up to $75.0 million. Any sales of common units under the ATM Program may be made by any method permitted by law deemed to be an at-the-market offering defined by Rule 415 of the Securities Act, including, without limitation, sales made directly on the New York Stock Exchange, on any other existing trading market for our common units or to or through a market maker. For the year ended December 31, 2014, we received net proceeds from the sale of 1,521,846 newly issued common units of $26.0 million, after deducting underwriting discounts and commissions and offering expenses of $0.8 million, and used the proceeds for general partnership purposes. For the year ended December 31, 2014, we paid approximately $0.5 million of aggregate compensation to MLV for sales under the ATM Program. Our second lien term loan requires that 50% of the net cash proceeds from any equity offering be used to repay borrowings outstanding under the term loan. This requirement is waived through March 31, 2015 (Note 7). We may continue to utilize our ATM Program as a source of cash after considering the current market price of our units.

We enter into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 65% to 85% of our estimated production from total proved developed producing reserves over a three-to-five year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

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 attempts 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

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of the next four quarters. In addition, our partnership agreement allows our general partner to borrow funds to make distributions.

Based on the number of common units, subordinated units and general partner units outstanding as of February 27, 2015, distributions to all of our unitholders at our current quarterly distribution rate would total $14.0 million. If commodity prices remain at current levels or further decline, we may consider a reduction in our quarterly distribution based on our liquidity and cash on hand.

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. In addition, a significant portion of our production is hedged. We are generally 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 generally do not receive the proceeds from the sale of our hedged production until 45 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 are 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 make working capital borrowings to fund our distributions. Because we distribute all of our available cash, we will not have those amounts available to reinvest in our business to increase our proved reserves and production and as a result, we may not grow as quickly as other oil and gas entities or at all.

We are committed to reinvesting a sufficient amount of our cash flow to fund our exploitation and development capital expenditures in order to maintain our production, and we intend to use primarily external financing sources, including commercial bank borrowings and the issuance of debt and equity interests, rather than cash reserves established by our general partner, to make acquisitions to further increase our production and proved reserves. Because our proved reserves and production decline continually over time and because we do not own any material undeveloped properties or leasehold acreage, we will need to make acquisitions to sustain our level of distributions to unitholders over time.

If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures, reduce distributions to 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. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our credit facility and term loan. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

Capital Expenditures

Based on the significant decline in commodity prices since the third quarter of 2014, we significantly reduced our capital expenditure budget in 2015 from 2014. We expect to spend $19.0 million in total capital expenditures in 2015. Our 2015 budget consists entirely of maintenance capital expenditures. We may further reduce our capital expenditure budget as we continue to monitor commodity prices and liquidity.

Maintenance capital expenditures represent our estimate of the amount of capital required on average per year to maintain our production over the long term. The primary purpose of maintenance capital is to maintain our production at a steady level over the long term to maintain our distributions per unit.

Growth capital expenditures are capital expenditures that we expect to increase our production and the size of our asset base. The primary purpose of growth capital expenditures is to acquire producing assets that will increase our distributions per unit and secondarily increase the rate of development and production of our existing properties in a manner that is expected to be accretive to our unitholders. Growth capital expenditures may include projects on our existing asset base. Although we may make acquisitions during 2015, including potential acquisitions of producing properties from Lime Rock Resources, we have not estimated any growth capital expenditures related to potential opportunistic acquisitions because 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.

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Based upon current oil and natural gas price expectations and our commodity derivatives positions for the year ending December 31, 2014, which cover 96% of our estimated production from total proved developed producing reserves, we anticipate that our cash on hand, cash flow from operations, proceeds from our ATM Program and available borrowing capacity under our revolving credit facility will provide us sufficient working capital to fund our total planned 2015 capital expenditures and cash distributions.

However, future cash flows are 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. There can be no assurance that our operations and other capital resources will provide cash in amounts that are sufficient to maintain our planned levels of capital expenditures or annualized cash distributions.

We intend to pursue acquisitions of long-lived, low-risk producing oil and natural gas properties with reserve exploitation potential. We would expect to finance any significant acquisition of oil and natural gas properties in 2015 though external financing sources, including borrowings under our revolving credit facility and the issuance of debt and equity securities, including through our ATM program.

Credit Agreement

We, as guarantor, and our wholly owned subsidiary, OLLC, as borrower, are parties to a senior secured revolving credit facility, as amended, (the Credit Agreement) that matures on October 1, 2019. The Credit Agreement is a five-year, $750.0 million revolving credit facility with a current borrowing base of $260.0 million. The Intercreditor Agreement (as described below under Term Loan Agreement) limits the amount of indebtedness outstanding at any time under the Credit Agreement (including undrawn amounts under letters of credit) to an amount not to exceed $500.0 million in the aggregate.

Our Credit Agreement is reserve-based, and we are permitted to borrow under our Credit Agreement in an amount up to the borrowing base, which is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. Our borrowing base is subject to scheduled redetermination on a semi-annual basis based on an engineering report with respect to our estimated oil, NGL and natural gas reserves, which will take into account the prevailing oil, NGL and natural gas prices at such time, as adjusted for the impact of our commodity derivative contracts. Unanimous approval by the lenders is required for any increase to the borrowing base. In the future, we may be unable to access sufficient capital under our Credit Agreement as a result of (i) a subsequent borrowing base redetermination or (ii) an unwillingness or inability on the part of our lenders to agree to an increase to the borrowing base or meet their funding obligations.

Based upon current commodity prices, we anticipate a lower borrowing base at our next redetermination process during the second quarter of 2015. If the borrowing base is reduced to a level below current outstanding indebtedness, we could be required to repay any indebtedness in excess of the borrowing base, or we could be required to pledge other oil and natural gas properties as additional collateral. We do not anticipate having any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our Credit Agreement. Additionally, we will not be able to pay distributions to our unitholders in any such quarter in the event there exists a borrowing base deficiency or an event of default either before or after giving effect to such distribution or we are not in pro forma compliance with the Credit Agreement after giving effect to such distribution.

Borrowings under the Credit Agreement are secured by liens on substantially all of our properties, but in any event, not less than 80% of the PV-10 value of our oil and natural gas properties, and all of our equity interests in OLLC and any future guarantor subsidiaries and all of our and our subsidiaries other assets including personal property. Additionally, borrowings under the Credit Agreement bear interest, at OLLC s option, at either (i) the greater of the prime rate as determined by the Administrative Agent, the federal funds effective rate plus 0.50%, and the 30-day adjusted LIBOR plus 1.0%, all of which is subject to a margin that varies from 0.50% to 1.50% 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 1.50% to 2.50% 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.

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Our Credit Agreement requires maintenance of a ratio of Total Debt (as such term is defined in the Credit Agreement) to EBITDAX, which we refer to as the leverage ratio, of not more than 4.0 to 1.0x, and a ratio of consolidated current assets to consolidated current liabilities, which we refer to as the current ratio, of not less than 1.0 to 1.0x. Our Credit Agreement defines EBITDAX as consolidated net income plus the sum of interest, income taxes, depreciation, depletion, amortization, accretion, impairment charges, exploration expenses and other noncash charges, minus all noncash income.

Additionally, the Credit Agreement contains various covenants and restrictive provisions which limit our, OLLC s and any of our subsidiaries ability to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of our assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of our production; and prepay certain indebtedness.

Events of default under the Credit Agreement include, but are not limited to, failure to make payments when due; any material inaccuracy in the representations and warranties of OLLC; the breach of any covenants continuing beyond the cure period; a matured payment default under, or other event permitting acceleration of, any other material debt; a change in management or change of control; a bankruptcy or other insolvency event; and certain material adverse effects on our business.

If we fail to perform our obligations under these and other covenants, the revolving credit commitments could 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, 2014, we were in compliance with all covenants contained in the Credit Agreement.

At December 31, 2014, we had $230.0 million of outstanding borrowings under our Credit Agreement and available borrowing capacity of $30.0 million.

Our borrowing base is expected to be reviewed by our lending group in the second quarter of 2015. As discussed above, our Credit Agreement is reserve-based, and we anticipate our borrowing base will be reduced due to a decline in the estimated future net realizable commodity prices since October 2014, the last time our borrowing base was reviewed. As of February 27, 2015, we had approximately $240.0 million of outstanding borrowings under our Credit Agreement and available borrowing capacity of approximately $20.0 million. Based on the current commodity price environment and our 2014 year end proved reserves, our borrowing base may be reduced below our current outstanding borrowings. We are reviewing alternatives to reduce our outstanding debt under the Credit Agreement, which may include the issuance of debt and equity and the sale of assets (subject to the limitations set forth in the Credit Agreement).

Term Loan Agreement

We, as parent guarantor, and our wholly owned subsidiary, OLLC, as borrower, entered into a Second Lien Credit Agreement (the Term Loan Agreement). The Term Loan Agreement provides for a $50 million senior secured second lien term loan to OLLC. OLLC borrowed $50 million under the Term Loan Agreement and used the borrowings to repay outstanding borrowings under the Credit Agreement.

The obligations under the Term Loan Agreement are guaranteed on a joint and several basis by us. The obligations are secured by a second priority mortgage and security interest in all assets of OLLC and us that secure OLLC s and our existing indebtedness under the Credit Agreement.

Borrowings under the Term Loan Agreement mature on April 1, 2020, and, subject to the terms of the Intercreditor Agreement (as described in the Term Loan Agreement), OLLC has the ability at any time to prepay the Term Loan Agreement without premium or penalty. Borrowings under the Term Loan Agreement bear interest, at OLLC s option, at either

- the greatest of (i) the prime rate as defined in the Term Loan Agreement, (ii) the federal funds effective rate plus 0.50% and (iii) the 30-day adjusted LIBOR plus 1.0%, all of which is subject to

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an applicable margin of 7.5%; or

- the applicable reserve-adjusted LIBOR plus an applicable margin of 8.5%.

The Term Loan Agreement contains various covenants and restrictive provisions which limit the ability of OLLC, us or any of our subsidiaries to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of its assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of production; prepay certain indebtedness; and amend the Credit Agreement or grant any liens to secure any indebtedness under the Credit Agreement. The Term Loan Agreement allows us to exclude certain sales of common units representing limited partner interests in us made on and after October 1, 2014 and on and before March 31, 2015 from compliance with the mandatory prepayment provision under the Term Loan Agreement that requires us to use 50% of the net cash proceeds from any equity offering to prepay borrowings outstanding under the Term Loan Agreement.

The Term Loan Agreement also contains covenants that, among other things, require OLLC and us to maintain specified ratios including leverage ratio of Total Debt to EBITDAX of not more than 4.25 to 1.00x; a current ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0x; and an asset coverage ratio of Total Proved PV-10 to Total Debt of not less than 1.50 to 1.00x. As of December 31, 2014, we were in compliance with the leverage and current ratios contained in our Term Loan Agreement. We are required to test the asset coverage ratio at specified intervals as described in the Term Loan Agreement. The next scheduled testing of the asset coverage ratio will occur in connection with our next borrowing base redetermination that will take place in the second quarter of 2015. As the result of current commodity prices, we anticipate that we will not meet the requirements of the asset coverage ratio. Based on preliminary discussions with the lender, we believe we will be able to obtain a waiver. However, there can be no assurance that we will be able to obtain a waiver. If we are unable obtain waiver, we will have to undertake alternative financing plans to reduce our indebtedness under the Term Loan Agreement, including, but not limited to, the issuance of public and private debt and equity securities and the sale of assets.

The obligations under the Term Loan Agreement and the Credit Agreement are governed by an Intercreditor Agreement with OLLC as borrower and us as parent guarantor, which (i) provides that any liens on the assets and properties of OLLC, the Partnership or any of their subsidiaries securing the indebtedness under the Term Loan Agreement are subordinate to liens on the assets and properties of OLLC, the Partnership or any of their subsidiaries securing indebtedness under the Credit Agreement and derivative contracts with lenders and their affiliates and (ii) sets forth the respective rights, obligations and remedies of the lenders under the Credit Agreement with respect to their first-priority liens and the lenders under the Term Loan Agreement with respect to their second-priority liens.

Commodity Derivative Contracts

The following table summarizes, for the periods presented, the weighted average price and notional volumes of our oil, NGL and natural gas swaps in place as of December 31, 2014. The weighted average price is based on the swap price for oil, NGL and natural gas swaps. We use swaps as a mechanism for managing commodity price risks whereby we pay the counterparty floating prices and receive fixed prices from the counterparty. By entering into the hedge agreements, we mitigate the effect on our cash flows of changes in the prices we receive for our oil, NGL, and natural gas production.

Term		Oil (NYMEX-WTI) Weighted Average $/Bbl	Bbls/d		NGL (Mount Belvieu) Weighted Average $/Bbl	Bbls/d		Natural Gas (NYMEX-Henry Hub) Weighted Average $/Mmbtu	Mmbtu/d
2015	$	93.16	2,075	$	34.46	647	$	5.72	15,069
2016	$	87.27	1,672	$			$	4.29	14,887
2017	$	84.34	1,298	$			$	4.61	13,824
2018	$	82.26	1,541	$			$	4.28	6,506

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The following table summarizes, for the periods presented, our natural gas basis swaps in place as of December 31, 2014. These contracts are designed to effectively fix a price differential between the NYMEX-Henry Hub price and the index price at which the physical natural gas is sold.

	Centerpoint East		Houston Ship Channel		WAHA		TEXOK	
Term	**$/Mmbtu**	**Mmbtu/d**	**$/Mmbtu**	**Mmbtu/d**	**$/Mmbtu**	**Mmbtu/d**	**$/Mmbtu**	**Mmbtu/d**
2015	$ (0.2291)	5,939	$ (0.0959)	3,031	$ (0.1380)	4,777	$ (0.1334)	846
2016	$		$ (0.0810)	2,691	$ (0.1326)	4,408	$ (0.0975)	784

The following table summarizes, for the periods presented, our oil basis swaps in place as of December 31, 2014. These contracts are designed to effectively fix a price differential between the NYMEX-WTI price and the index price at which the physical oil is sold.

	Argus Midland-Cushing	
Term	**$/Bbl**	**Bbl/d**
2015	$ (3.4087)	1,088

Cash Flows

Cash flows provided by (used in) by type of activity were as follow for the periods indicated (in thousands):

	Year Ended December 31,		
	2014	**2013**	**2012**
Net cash provided by (used in):			
Operating activities	$ 67,885	$ 65,541	$ 77,223
Investing activities	(69,950)	(35,805)	(40,433)
Financing activities	1,224	(28,786)	(34,836)

Operating Activities. Net cash provided by operating activities was $67.9 million, $65.5 million, and $77.2 million for the years ended December 31, 2014, 2013, and 2012, respectively. Revenues fluctuate due to the volatility of commodity prices, and therefore our cash provided by operating activities is impacted by the prices received for oil and natural gas sales, as well as levels of production volumes and operating expenses.

Our working capital totaled $49.5 million and $17.1 million at December 31, 2014 and 2013, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $3.6 million and $4.4 million at December 31, 2014 and 2013, respectively.

Investing Activities. Net cash used in investing activities was $70.0 for the year ended December 31, 2014, which primarily represented $37.6 million for acquisition of oil and gas natural properties and $32.4 million of additions to our property and equipment balances. Net cash used in investing activities was $35.8 million and $40.4 million for the years ended December 31, 2013 and 2012, respectively, which primarily represented additions to our property and equipment balances during the periods.

Financing Activities. Cash flows provided by financing activities of $1.2 million for the year ended December 31, 2014 consisted of net proceeds received from an equity offering of $26.0 million and net borrowings under the Credit Agreement of $30.0 million offset by distributions to unitholders of $53.4 million and deferred financing costs of $1.3 million.

Cash flows used in financing activities of $28.8 million for the year ended December 31, 2013 consisted of net proceeds received from an equity offering of $59.5 million and net borrowings under the Credit Agreement of $22.0 million offset by contributions and distributions to Lime Rock Resources associated with acquisitions of $61.4 million and distributions to unitholders of $48.9 million.

Cash flows used in financing activities of $34.8 million for the year ended December 31, 2012 included distributions paid to our unitholders of $37.3 million, distributions and contributions to Fund I of $69.2 million and

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deferred financing costs of $0.5 million, offset by net borrowings of $72.2 million.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2014 is provided in the following table (in thousands).

			Obligations Due in Period			
Contractual Obligation	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**
Long-term debt (1)	$	$	$	$	$ 280,000	$ 280,000
Interest on long-term debt(2)	10,824	10,824	10,824	10,824	10,373	53,669
Total	$ 10,824	$ 10,824	$ 10,824	$ 10,824	$ 290,373	$ 333,669

(1) Represents amounts outstanding under our Credit Agreement and Term Loan Agreement as of December 31, 2014. The total balance of our Credit Agreement will mature in October 2019 and the balance on our Term Loan Agreement will mature in April 2020.

(2) Based upon the weighted average interest rate of approximately 2.68% under the Credit Agreement at December 31, 2014 and an unused commitment fee of 0.50% on $30.0 million and the weighted average interest rate of 9.02% under the Term Loan Agreement.

The table above excludes amounts associated with our oil and natural gas property asset retirement obligations. As of December 31, 2014, $41.6 million of such obligations were recorded as liabilities, $1.1 million of which was reflected as current liabilities. Due to the nature of these obligations, we cannot determine precisely when the payments will be made to settle these obligations.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Estimates and assumptions are evaluated on a regular basis. We based our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of the financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made; and

- changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated results of operations or financial condition.

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Below is a discussion of the more significant accounting policies, estimates and judgments. See Note 2 Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in this report for a discussion of additional accounting policies and estimates made by management.

Third-Party Acquisitions

Accounting for third-party acquisitions requires that the various assets acquired and liabilities assumed in a business combination be recorded at their respective fair values. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The most significant estimates to us typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties.

The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties included estimates of: (i) reserves, including risk adjustments for probable and possible reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; (v) future cash flows; and (vi) a market-based weighted average cost of capital rate.

Deferred taxes are recorded for any differences between the fair value and tax basis of assets acquired and liabilities assumed. To the extent the purchase price plus the liabilities assumed (including deferred income taxes recorded in connection with the transaction) exceeds the fair value of the net assets acquired, we are required to record the excess as goodwill (or bargain purchase if there is a shortfall of purchases price versus net fair value recorded). As the fair value of assets acquired and liabilities assumed is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

We recorded the assets acquired and liabilities assumed in the October 2014 Acquisition at their estimated fair value of approximately $38.2 million, which we consider to be representative of the price paid by a typical market participant. Based on the purchase price allocation for our October 2014 Acquisition, no goodwill or bargain purchase was recorded.

Transactions Between Entities Under Common Control

Master limited partnerships (MLPs) enter into transactions whereby the MLP receives a transfer of certain assets from its sponsor or predecessor for consideration of either cash, units, assumption of debt, or any combination thereof. We account for the net assets received using the carryover book value of Lime Rock Resources as these were considered to be transactions between entities under common control. Our historical financial statements have been revised to include the results attributable to the assets contributed from Lime Rock Resources as if we owned such assets for all periods presented by us. The following financial statement items were impacted:

Oil and Natural Gas Properties Received. The book value and related activity of oil and natural gas properties received from Lime Rock Resources is determined using the carrying value of the specific assets contributed.

Commodity Derivative Instruments. Reflects the fair value of the commodity derivative contracts associated with the properties acquired from Lime Rock Resources.

Asset Retirement Obligations Received. The book value and related activity of asset retirement obligations received from Lime Rock Resources was determined by using the carrying value of the specific liabilities attributable to the assets contributed.

Oil, Natural Gas and NGL Revenues and Expenses. Oil, natural gas and NGL revenues and expenses related to the properties acquired were based on the actual results of the acquired properties. Historical lease operating statements by individual asset were used as the basis for revenues and direct operating expenses.

Gain (Loss) on Commodity Derivative Contracts, Net. Reflects the net gain (loss) on commodity derivative contracts associated with the properties acquired assuming the contracts were in place as of the date acquired by Lime Rock Resources.

General and Administrative Expense. The general and administrative expense attributable to the properties acquired was determined by the ratio of production for the properties acquired to the total respective Lime Rock Resources production for the period presented.

Oil, NGL and Natural Gas Reserve Quantities

Our estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Miller and Lents, Ltd., Netherland, Sewell & Associates, Inc. and Ryder Scott Petroleum Consultants, our independent reserve engineering firms, prepare a fully-engineered reserve and economic evaluation of all our properties on a lease, unit or well-by-well basis, depending on the availability of well-level production data. The estimates of the proved reserves as of December 31, 2014 included in this report are based on reserve reports prepared by Miller and Lents, Ltd., Netherland, Sewell & Associates, Inc. and Ryder Scott Petroleum Consultants.

We prepare our reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. Our independent engineering firms adhere to the same guidelines when preparing their reserve reports. 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 flows are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in our estimated cash flows are the product of a process that begins with NYMEX 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 depletion and depreciation 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.

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Unproved Properties

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 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 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, and the relative proportion of such properties on which proved reserves have been found in the past. The fair values of unproved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of 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, 2014, we recorded a non-cash impairment charge of $37.8 million on our proved oil and natural gas properties in the Permian Basin and Mid-Continent regions. We recorded a non-cash impairment charge of $63.7 million related to our proved oil and natural gas properties during the year ended December 31, 2013. We recorded a non-cash impairment charge of $3.1 million related to our proved oil and natural gas properties during the year ended December 31, 2012. The carrying values of the impaired proved properties were reduced to fair value measured by estimated cash flows reporting in an internal reserve report. These reports are based upon future oil and natural gas prices, which are based on observable inputs, adjusted for basis differentials. These are classified as Level 3 measurements. The charges are included in impairment of oil and natural gas properties in our condensed statements of operations. If future oil and natural gas prices or reserves decline during 2015, the estimated undiscounted cash flows for the proved oil and natural gas properties may not exceed the net capitalized costs for our recently acquired properties and a non-cash impairment charge may be required to be recognized in future periods. As of February 27, 2015, the NYMEX-WTI oil spot price was $49.76 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.75 per MMBtu.

Asset Retirement Obligations

The initial estimated asset retirement obligation associated with oil and natural gas properties is recognized at fair value as a liability, with a corresponding increase in the carrying value of oil and natural gas properties when the legal obligation is incurred. 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 asset retirement obligation and the asset retirement cost. 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 and Natural Gas Balancing

Oil and natural gas revenues are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. We account for oil and natural gas production imbalances using the sales method, whereby we recognize revenue on all natural gas and oil sold to our customers notwithstanding the fact that its ownership may be less than 100% of the oil and natural gas sold. Liabilities are recorded for imbalances greater than our respective proportionate share of remaining estimated and oil natural gas reserves.

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,

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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 either exchange-traded or transacted in an over-the-counter market. Valuation is determined by reference to readily available public data.

We recognize all of our derivative contracts as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative contract depends on whether it has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. None of our derivatives were designated as a hedging instrument during 2014, 2013, or 2012. For our non-designated derivative contracts, the gain or loss is recognized in current earnings during the period of change.

Recently Issued Accounting Pronouncements

Refer to Note 2 of the consolidated financial statements.

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, 2014, 2013, or 2012. 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 and natural gas prices increase drilling activity in our areas of operations.

Off-Balance Sheet Arrangements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES 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 and natural gas production. Realized pricing is primarily driven by the spot market prices applicable to its natural gas production and the prevailing price for oil. Pricing for oil and natural gas 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 and natural gas production depend on many factors outside of our control, such as the strength of the global economy.

To reduce the impact of fluctuations in oil and natural gas 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 and natural gas production through various transactions that fix the future prices received. These transactions may include price swaps whereby we receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate of the fixed ceiling price. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. We do not enter into derivative contracts for speculative trading purposes.

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In a typical commodity swap agreement, including basis swaps, 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 our hedged production. Our swaps are settled in cash on a monthly basis. In a typical collar arrangement, we receive the excess, if any, of the floor price over the reference price, based on NYMEX quoted prices, and pay the excess, if any, of the reference price over the ceiling price.

The following table summarizes our open commodity derivative contracts as of December 31, 2014:

Natural gas positions					
Price swaps (MMBTUs)	NYMEX-HH	5,500,236	5,433,888	5,045,760	2,374,800
Weighted average price		$ 5.72	$ 4.29	$ 4.61	$ 4.28
Basis swaps (MMBTUs)	(1)	5,326,559	2,877,047		
Weighted average price		$ (0.1661)	$ (0.1115)	$	$
Oil positions					
Price swaps (BBLs)	NYMEX-WTI	757,321	610,131	473,698	562,524
Weighted average price		$ 93.16	$ 87.27	$ 84.34	$ 82.26
Basis swaps (BBLs)	Argus-	397,035			
Weighted average price	Midland-Cushing	$ (3.4087)	$	$	$
NGL positions					
Price swaps (BBLs)	Mont Belvieu	236,149			
Weighted average price		$ 34.46	$	$	$

(1) Our natural gas basis swaps are traded on the following indices: Centerpoint East, Houston Ship Channel, WAHA and TEXOK.

As of December 31, 2014, the fair market value of our commodity derivative positions was a net asset of $83.7 million.

Interest Rate Risk

At December 31, 2014, we had $280.0 million of debt outstanding under our Credit Agreement and Term Loan, with an average effective interest rate of 3.81%. 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 $1.1 million per year.

Counterparty and Customer Credit Risk

Our oil and natural gas 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, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty s credit rating and latest financial information. The counterparties to our derivative contracts currently in place are lenders under our credit facility, with investment grade ratings.

We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, our customer base consists of major

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integrated and international oil and natural gas companies, as well as smaller processors and gatherers. We believe the credit quality of our customers is high.

Joint interest receivables arise from entities which own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we drill. We have limited ability to control participation in our wells.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Our Consolidated Financial Statements are included in this Annual Report on Form 10-K beginning on page F-1.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officers and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officers and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Our principal executive officers and principal financial officer, with the participation of management, have concluded that our disclosure controls and procedures were effective to provide reasonable assurance level as of December 31, 2014.

Management s Report on Internal Control over Financial Reporting

See Management s Report on Internal Control over Financial Reporting included in this Annual Report on Form 10-K beginning on page F-1.

Changes in Internal Controls over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter and year ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Our general partner manages our operations and activities on our behalf through our executive officers and board of directors. Our general partner is ultimately controlled by the co-founders of Lime Rock Management, who also ultimately control Lime Rock Resources and Lime Rock Partners. As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for the management or

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operations of our business. These functions are performed by the employees of Lime Rock Management and ServCo pursuant to a services agreement. As such, all of our general partner s executive officers are employees of Lime Rock Management.

Our general partner is not elected by our unitholders and is not subject to re-election on an annual or other continuing basis. Unitholders are not entitled to elect the directors of our general partner, who are all appointed by Lime Rock Management, or to participate directly or indirectly in our management or operations. Our general partner owes a fiduciary duty to our unitholders. However, our partnership agreement contains provisions that reduce the fiduciary duties that our general partner owes to our unitholders.

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. Mr. Eric Mullins serves as the Chairman of the board and Co-Chief Executive Officer of our general partner. Our general partner s board of directors has determined that the combined roles of Chairman and Co-Chief Executive Officer allow the board to take advantage of the leadership skills of Mr. Mullins and is appropriate because Mr. Mullins works closely with our management team on a daily basis and is in the most knowledgeable position to determine the timing for board meetings and propose agendas for meetings. However, any director can establish agenda items for a board meeting. Our general partner s board of directors has also determined that having each of the Co-Chief Executive Officers serve as directors enhances 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 responsibility for enterprise-level risk management, while retaining its primary responsibility for oversight of our executive officers in that regard. Our executive officers offer an enterprise-level risk assessment to the board of directors at least once every year.

Directors and Executive Officers

The following table sets forth certain information regarding the directors and executive officers of our general partner.

Name	Age	Position with our General Partner
Eric Mullins	52	Co-Chief Executive Officer and Chairman
Charles W. Adcock	61	Co-Chief Executive Officer and Director
Christopher A. Butta	54	Senior Vice President of Engineering and Chief Engineer
Jaime R. Casas	45	Vice President and Chief Financial Officer
C. Timothy Miller	55	Executive Vice President and Chief Operating Officer
John A. Bailey (1)	44	Director
Jonathan Carroll (2)	53	Director
Jonathan C. Farber	46	Director
Robert T. O Connell (3)	76	Director
Townes G. Pressler, Jr.	51	Director

(1) Chairman of the conflicts committee and member of the audit committee.

(2) Member of the conflicts and audit committees.

(3) Chairman of the audit committee and member of the conflicts committee.

Directors are elected by Lime Rock Management. Our general partner s directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been appointed and qualified. Officers serve at the discretion of the board of directors. All of our executive officers, other than our Chief Financial Officer who is devoted full-time to our business, also serve as executive officers of Lime Rock Resources, an affiliate of our general partner. There are no familial relationships among any of our general partner s directors or executive officers. In evaluating director candidates, Lime Rock Management will assess whether a candidate

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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 Lime Rock Management may consider diversity among other factors when considering director nominees, it did not apply any specific policy with regard to selecting and appointing directors to the board of directors. However, when appointing new directors, Lime Rock Management 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.

Eric Mullins Co-Chief Executive Officer and Chairman. Eric Mullins was appointed Co-Chief Executive Officer and the Chairman of the board of directors of our general partner in May 2011. Mr. Mullins also serves as a Managing Director and Co-Chief Executive Officer of Lime Rock Resources, which positions he has held since April 2005 and October 2008, respectively. Prior to joining Lime Rock Resources, Mr. Mullins worked in the Investment Banking Division of The Goldman Sachs Group, Inc. from August 1990 to April 2005, serving as a Vice President from 1994 to 1999 and as a Managing Director from 1999 to April 2005. Mr. Mullins spent almost all of those 15 years at Goldman Sachs in the Energy & Power Group, where he led numerous financing, structuring, and strategic advisory transactions. Mr. Mullins has served as a director of Anadarko Petroleum Corporation since May 2012, where he is chairman of the audit committee. Mr. Mullins is a graduate of Stanford University, with a Bachelor of Arts degree, and the Wharton School of the University of Pennsylvania, with a Master of Business Administration. We believe that Mr. Mullins extensive experience in the investment banking industry related to energy transactions, as well as his relationships with Lime Rock Management and its affiliated funds, particularly his service as the Co-Chief Executive Officer of Lime Rock Resources, bring important experience and skill to the board of directors.

Charles W. Adcock Co-Chief Executive Officer and Director. Charles W. Adcock was appointed Co-Chief Executive Officer and a member of the board of directors of our general partner in May 2011. Mr. Adcock also serves as a Managing Director and Co-Chief Executive Officer of Lime Rock Resources, which positions he has held since May 2005 and October 2008, respectively. From 1993 to 2004, Mr. Adcock worked in various positions at The Houston Exploration Company, a publicly traded independent North American oil and natural gas producer, serving as its Senior Vice President from 2001 through December 2004, at which time he retired, and the head of its Acquisitions group from 1993 to 2000. Prior to joining Houston Exploration, Mr. Adcock held various engineering and managerial positions with NERCO Oil & Gas, Union Texas Petroleum, Apache Corporation, American Natural Resources and Aminoil USA. Mr. Adcock is a graduate of Texas A&M University, with a Bachelor of Science degree in Civil Engineering, and the University of St. Thomas, with a Master of Business Administration. We believe that Mr. Adcock s experience at independent exploration and production companies in the energy industry, as well as his relationships with Lime Rock Management and its affiliated funds, particularly his service as the Co-Chief Executive Officer of Lime Rock Resources, bring important experience and skill to the board of directors.

Christopher A. Butta Senior Vice President of Engineering and Chief Engineer. Christopher A. Butta was appointed Senior Vice President of Engineering and Chief Engineer of our general partner in March 2015. Mr. Butta also was appointed Senior Vice President of Engineering and Chief Engineer of Lime Rock Resources in March 2014. From May 2011 to March 2015, Mr. Butta served as Vice President and Chief Engineer of our general partner. From October 2008 to March 2014, Mr. Butta served as Vice President and Chief Engineer of Lime Rock Resources. From July 2005 to October 2008, Mr. Butta served as the Vice President of Engineering of Lime Rock Resources. From 1991 through July 2005, Mr. Butta worked for Miller and Lents, Ltd., a leading domestic and international consulting firm specializing in oil and gas reserve evaluations and economic analyses. During his 14 years at Miller and Lents, Mr. Butta rose from Consulting Engineer to Senior Vice President. In those capacities, he analyzed oil and gas reserves throughout the United States to provide engineering reserve estimates. Prior to that, Mr. Butta spent eight years as an operations/analytical engineer at ARCO Oil and Gas Company. Mr. Butta is a graduate of the University of Missouri-Rolla, with a Bachelor of Science degree in Petroleum Engineering.

Jaime R. Casas Vice President and Chief Financial Officer. Jaime R. Casas was appointed Vice President and Chief Financial Officer of our general partner in July 2011. Prior to joining our general partner in June 2011, Mr. Casas served as Vice President, Chief Financial Officer of Laredo Energy, a privately held oil and gas company, from May 2009 to June 2011. While at Laredo Energy, Mr. Casas primary responsibilities were managing accounting, finance and certain business development functions. From November 2008 until joining Laredo Energy in May 2009, Mr. Casas worked as an independent financial consultant. From 1999 to October 2008 and 1995 to

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1997, Mr. Casas worked in various positions in the investment banking energy groups at Donaldson, Lufkin & Jenrette and at Credit Suisse following Credit Suisse s acquisition of DLJ, including as a Director, Vice President, Associate and Analyst. While at Credit Suisse, Mr. Casas primary focus was on capital and advisory transactions for exploration and production companies. From 1993 to 1995, Mr. Casas worked for Accenture as a management information consultant in the energy group. Mr. Casas is a graduate of Texas A&M University, with a Bachelor of Business Administration degree, and the Wharton School of the Un