LRR Energy, L.P.
Form 10-K
March 27, 2012
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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, 2011

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	**77002**
(Address of principal executive offices)	(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. x

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 o
	Smaller reporting company o

Non-accelerated filer x
(Do not check if a smaller reporting company)

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

As of June 30, 2011, the last business day of the registrant s most recently completed second fiscal quarter, the registrant s equity was not listed on any domestic exchange or over-the-counter market. The registrant s common units began trading on the New York Stock Exchange on November 11, 2011.

There were 15,700,074 common units, 6,720,000 subordinated units and 22,400 general partner units outstanding as of March 16, 2012.

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

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

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

Field: An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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.

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

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

Proved Undeveloped Reserves: Proved oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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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.

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

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

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

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.

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, which 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 the minimum quarterly distribution 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 oil, natural gas or NGL prices;*
- *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 in our credit facility;*
- *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.*

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. and its wholly owned operating subsidiary, LRE Operating, LLC (OLLC). 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 Lime Rock Resources refer collectively to Fund I and Fund II.

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.

In connection with the completion of our IPO on November 16, 2011, pursuant to a contribution, conveyance and assumption agreement, we acquired specified oil and natural gas properties and related net profits interests and operations and certain commodity derivative contracts (the Partnership Properties) owned by LRR A, LRR B, and LRR C. For further discussion regarding our IPO, please see the discussion under Initial Public Offering of LRR Energy, L.P. and Related Transactions below and Note 1 to the audited consolidated/combined financial statements included in this Annual Report.

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, 2011, our total estimated proved reserves were approximately 28.8 MMBoe, of which approximately 85% were proved developed reserves (approximately 70% proved developed producing and approximately 15% proved developed non-producing). As of December 31, 2011, we operated 93% of our proved reserves. Our proved reserves had a standardized measure of $342.3 million as of December 31, 2011. Our proved reserves by area are as follows:

Proved Reserves by Operating Region as of December 31, 2011

Operating Region	MBoe	% of Total Reserves	% Proved Developed	% Oil and NGLs	% Operated
Permian Basin Region	15,341	53%	79%	60%	93%
Mid-Continent Region	10,041	35%	94%	0%	92%
Gulf Coast Region	3,468	12%	88%	30%	100%
All Regions	28,850	100%	85%	36%	93%

Initial Public Offering of LRR Energy, L.P. and Related Transactions

On November 16, 2011, we completed our IPO of 9,408,000 common units representing limited partner interests in the Partnership at a price to the public of $19.00 per common unit, or $17.8125 per common unit after payment of the underwriting discount. Total net proceeds from the sale of common units in our IPO were $167.2 million ($178.8 million less $11.2 million for the underwriting discount and a $0.4 million structuring fee). IPO costs were approximately $4.7 million. Net proceeds of the offering, along with $155.8 million of borrowings under our $500 million senior secured revolving credit agreement, as further discussed below, were utilized to make cash distributions and payments to Fund I of approximately $289.9 million and repay $27.3 million of LRR A s debt that we assumed at closing.

On December 14, 2011, we closed the partial exercise of the underwriters option to purchase additional units and issued an additional 1,200,000 common units to the public. We used the net proceeds from the sale of the

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additional common units of $21.3 million, after deducting underwriting discounts and a structuring fee, to pay additional cash consideration for the properties purchased from Fund I in connection with the IPO and to make additional distributions to Fund I. In connection with our IPO, Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and the assumption of $27.3 million of LRR A s indebtedness.

As of March 16, 2012, we had 15,700,074 common units, 6,720,000 subordinated units and 22,400 general partner units outstanding. In addition, as of March 16, 2012, Fund I owned 5,049,600 common units and all of our subordinated units, representing an approximate 52.4% limited partner interest in us.

Credit Agreement

In July 2011, we, as guarantor, and OLLC, as borrower, entered into a five-year, $500 million senior secured revolving credit facility (the Credit Agreement) that matures in July 2016. The Credit Agreement is reserve-based and we are permitted to borrow under our credit facility in an amount up to the borrowing base, which is currently $250 million. Our borrowing base, which is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts, is subject to redetermination semi-annually by our lenders at their sole discretion. Unanimous approval by the lenders is required for any increase to the borrowing base.

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:

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

- 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.

- 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.

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 and financial flexibility.

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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 an approximate 52.4% limited partner interest in us. In addition, through its interest in our general partner, Lime Rock Resources is 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. (OpCo), 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 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 currently consists of two investment funds, Fund I, formed in 2005, and Fund II, formed in 2008. Lime Rock Resources successfully raised $456 million in Fund I and $410 million in Fund II and has a high quality team of 64 industry professionals who provide services to us pursuant to the services agreement. Since 2006, Lime Rock Resources invested approximately (i) $416 million of Fund I equity and $277 million of Fund I leverage and (ii) $182 million of Fund II equity and $162 million of Fund II leverage in 12 major acquisitions of oil and natural gas properties in three diverse producing regions. Lime Rock Resources currently has approximately $497 million of additional acquisition capacity that it expects to deploy over the next two years.

Lime Rock Resources is managed and operated by Lime Rock Management and OpCo. Most of the executive officers of Lime Rock Resources, including Mr. Charles Adcock and Mr. Eric Mullins, 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 20.0 MMBoe as of December 31, 2011, of which approximately 85% were proved developed reserves, with a standardized measure of $438.0 million as of December 31, 2011 and average net production of approximately 9,504 Boe/d for the twelve months ended December 31, 2011. The oil and natural gas properties owned by Lime Rock Resources include properties with characteristics similar to the Partnership 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, onshore producing oil and natural gas properties and to offer us the opportunity to participate in potential joint acquisition opportunities. 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

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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.

Given its significant ownership in us, we believe Lime Rock Resources is positioned to directly benefit from selling additional oil and natural gas properties to us. As a result, 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. 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.

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. Lime Rock Partners consists of six funds: the first Lime Rock Partners fund, a $105 million fund established in October 1998; Lime Rock Partners II, L.P., a $320 million fund established in August 2002; Lime Rock Partners III, L.P., a $431 million fund established in November 2004; Lime Rock Partners IV, L.P., a $768 million fund established in September 2006; Lime Rock Partners V, L.P., a $1.4 billion fund established in April 2008 and Lime Rock Partners VI, L.P, established in December 2011. 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 investment team consists of approximately 29 professionals in five offices: Houston, Texas; Westport, Connecticut; London, England; Aberdeen, Scotland; and Dubai, United Arab Emirates. The 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:

	Partnership	Predecessor

	2011(1)	2011(1)	2010	2009
ConocoPhillips	25%	18%	16%	14%
Seminole Energy Services	16%	12%	13%	(2)
Upstream Energy	12%	(2)	10%	18%
Sunoco	(2)	16%	10%	11%
Square Mile Energy	(2)	(2)	(2)	13%

(1) In 2011, we evaluated concentration of credit risk for us and the predecessor by analyzing customer receipts from the oil and natural gas assets as if the predecessor transferred title of the properties to us on January 1, 2011.

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

ConocoPhillips and Sunoco 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 Energy Services 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, and Upstream Energy markets natural gas production from us pursuant to an existing marketing agreement that automatically renews quarterly until either party gives 30-day advance written notice of termination.

If we were to lose any one of our 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. We are unable to predict when, or if, such shortages 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.

Hydraulic Fracturing

Hydraulic fracturing has been a part of the completion process for 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 our properties in the Cowden Ranch area of Texas. Substantially all of our leasehold acreage is currently held by production from existing wells. Therefore, fracturing is not currently required to maintain this acreage but it will be required in the future to develop the 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.

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.

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

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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. This aspect of well design essentially eliminates a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. 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.

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

We minimize the use of water and dispose of it in a way that minimizes the impact to nearby surface water by disposing excess water and water that is produced back from the wells into approved disposal or injection wells. We currently do not discharge water to the surface. We intend to investigate the possibility of utilizing produced formation water or the fracturing fluid that is produced back from wells for use in hydraulic fracturing. However, the technology for treating these fluids for use in hydraulic fracturing is not readily available in our operating areas at this time.

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, 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 $3 million to $7.5 million and retentions ranging from $100,000 to $150,000. Our control of well policy insures us for blowout risks associated with drilling, completing and operating our wells, including above ground pollution.

We do not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to our hydraulic fracturing operations. However, we believe our general liability and excess liability insurance policies would cover third-party claims for property damage and bodily injury related to our hydraulic fracturing operations in accordance with, and subject to, the terms of such policies. These policies may not cover fines, penalties or costs and expenses related to government-mandated clean up of pollution. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, 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;

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- 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. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

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, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, we can give no assurance that we will continue to be in compliance or that future compliance requirements will not become overly burdensome in the future.

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

Hazardous Substances and Waste

The 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 U.S. Environmental Protection Agency, or EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can seek to impose administrative, civil and criminal penalties for alleged noncompliance with RCRA and analogous state requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil 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. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, 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. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, neighboring landowners and other third-parties may file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Despite the petroleum exclusion under CERCLA, we may generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to 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. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our financial condition or results of operations.

Water Discharges

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and hazardous substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. Spill prevention, control and countermeasure, or SPCC, plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws required individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Oil Pollution Act of 1990, as amended, or OPA, 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. OPA requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst case discharge of oil into waters of the United States.

Hydraulic Fracturing Regulation. It is customary to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate natural gas production. Hydraulic fracturing is also used to complete conventional vertical oil and gas wells. Due to public concerns raised regarding the potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. The U.S. Congress is considering 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. Members of Congress have also been investigating the activities of certain companies that provide hydraulic fracturing services. EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing activities, the results of which are anticipated to be available by late 2012. On October 21, 2011, the EPA also announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing, including states in which we operate. For example, the Railroad Commission of Texas, or RRC, recently adopted regulations which

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require disclosure of hydraulic fracturing fluids. The new regulations apply to all wells hydraulically fractured for which the RRC has issued a drilling permit after February 1, 2012. In addition, at least three local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities. 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 allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Adoption of legislation amending the Safe Drinking Water Act or of any implementing regulations placing restrictions on hydraulic fracturing activities 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.

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 23, 2011, the EPA published four sets of new rules that, if adopted, will impose 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. Texas is in the process of reviewing air permits that cover oil and gas exploration and production activities. Though the regulations ultimately adopted may change, we do not believe that such requirements will have a material adverse effect on our operations.

Climate Change

Recent 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.

On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or PSD, 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. EPA has determined that facilities that are required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to best available control technology standards for GHG that have yet to be developed. In addition, in October 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. In 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. Reporting of GHG emissions from such facilities is required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

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. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. In addition to these regulatory developments, judicial decisions related to certain tort claims alleging property damage may increase our litigation risk for such claims. The U.S. Supreme Court recently

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ruled that such actions were preempted under federal law but left open whether state level actions were preempted. 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 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 Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Currently, we have production activities on federal lands. Governmental permits or authorizations that are subject to the requirements of NEPA are required for our current activities and any future or proposed development plans on federal lands. This 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 previously unidentified 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.

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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.

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 us.

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.

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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.

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 us.

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 OpCo 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, 2011, OpCo had 64 employees, including six engineers, four geologists and six land professionals, who provide services to Lime Rock Resources and us. As of December 31, 2011, Lime Rock Management had 24 employees that provided services to both Lime Rock Resources and us, and had one employee that provided services only to us. Each of OpCo 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 OpCo 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 approximately 42,600 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 or before December 31, 2015.

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, 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.

ITEM 1A. RISK FACTORS.

Risks Related to Our Business

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

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We may not have sufficient available cash each quarter to pay the minimum quarterly distribution of $0.4750 per unit (or $10.7 million per quarter in the aggregate), 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;
- 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 minimum quarterly distribution 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 at 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.

A decline in oil, natural gas or NGL prices will cause a decline in our cash flow from operations, which could cause us to reduce our distributions or cease paying distributions altogether.

Lower oil and natural gas prices may decrease our revenues and thus cash available for distribution to our unitholders. Historically, oil and natural gas prices have been extremely volatile. For example, for the five years ended December 31, 2011, the NYMEX-WTI oil price ranged from a high of $145.29 per Bbl to a low of $31.41 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $13.31 per MMBtu to a low of $1.88 per MMBtu. As of March 26, 2012, the NYMEX-WTI oil spot price was $107.03 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.13 per MMBtu. A significant decrease in commodity prices may cause us to reduce the distributions we pay to our unitholders or we may cease paying distributions.

If commodity prices decline and 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.

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Significantly 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 and ability to fund our operations. As a result, we may reduce the amount of distributions paid to our unitholders or cease paying distributions.

Further, deteriorating commodity prices may cause us to recognize impairments in the value of our oil and natural gas properties. In addition, if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken and our ability to borrow funds under our credit facility to pay distributions to our unitholders.

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 removing 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

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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, 2011 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 $84.7 million, from $342.3 million to $257.6 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.

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;
- 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

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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 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.

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

Also, our reviews of 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.

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

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

Our credit facility restricts, among other things, our ability to incur debt and pay distributions, and requires us to comply with customary financial covenants and specified financial ratios. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of our credit facility that are not cured or waived within 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

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obligations under our credit facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our credit facility, the lenders could seek to foreclose on our assets.

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. A future decline in commodity prices could result in a redetermination that lowers our borrowing base in the future and, in such case, 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 to make any distributions to our unitholders.

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 several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or processing facility capacity could reduce our ability to market our oil and natural gas production and harm our business.

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 gasses could cause our operating costs to increase. The EPA is proceeding with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act beginning with large emitters. The EPA adopted a tiered approach to implementing the permitting of green house gas emissions from stationary sources in May 2010. The so-called tailoring rule only requires the stationary sources with the largest emissions to undergo an assessment of green house gas emissions under the best available control technology under the federal permitting programs. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large

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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 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.

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in July 2010, or the Dodd-Frank Act, establishes a new regulatory framework for derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on a derivatives clearing organization and traded on an exchange or a swap execution facility, and cash collateral will have to be posted. The Dodd-Frank Act requires the Commodity Futures and Trading Commission, or CFTC, federal regulators of banks and other financial institutions, or the prudential regulators, and the SEC to promulgate the rules implementing the new law, which are scheduled to be finally adopted in early 2012. Until these regulations are adopted, effective and implemented in practice, we cannot determine what impact the new regulatory framework will have on our business.

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

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

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 2014 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 Texas, where the Texas Railroad Commission recently adopted regulations requiring online disclosure of the chemicals used in hydraulic fracturing. 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.

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

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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 owns an approximate 52.4% limited partner interest in us and, through its interest 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 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;

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- 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 OpCo 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 OpCo 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 OpCo, 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, such as a prospective Fund III, which may commence raising capital to make acquisitions once 75% of the capital of Fund II has been allocated to acquisition opportunities and expenses of Fund II, 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. In addition, Lime Rock Resources has approximately $497 million of additional acquisition capacity that it expects to deploy over the next two years. Because of Lime Rock Resources economic interests to invest those funds, it is likely that they 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. 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 OpCo to manage our business. Most of our management team and the employees of OpCo provide substantially similar services to Lime Rock Resources, and thus are not solely focused on our business.

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Neither we nor our general partner have any employees and we rely solely on Lime Rock Management and OpCo to manage us and operate our assets. We are a party to a services agreement with Lime Rock Management and OpCo 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 OpCo provide substantially similar services and personnel to Lime Rock Resources. Should Lime Rock Resources form other funds, Lime Rock Management and OpCo may also enter into similar arrangements with those new funds. Because Lime Rock Management and OpCo provides services to us that are substantially similar to those provided to Lime Rock Resources and, potentially, other funds, Lime Rock Management and OpCo may not have sufficient human, technical and other resources to provide those services at a level that Lime Rock Management and OpCo 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 OpCo 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 OpCo favor us over Lime Rock Resources or other affiliated funds in providing its services. If the employees of Lime Rock Management and OpCo 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.

We have in the past identified material weaknesses in our internal controls over financial reporting, and the identification of any material weaknesses in the future could affect our ability to ensure timely and accurate financial statements.

In connection with the audit of our predecessor s financial statements for the year ended December 31, 2010, our predecessor s independent registered accounting firm identified and communicated material weaknesses in our predecessor s internal control over financial reporting. A material weakness is a control deficiency, or combination of control deficiencies, such that there is a reasonable possibility that a material misstatement of the annual or interim statements will not be prevented or detected on a timely basis. Accordingly, a material weakness increases the risk that the financial information we report contains material errors.

Although we have taken actions to remediate the past material weaknesses in our internal controls over financial reporting, these measures may not be sufficient to ensure that our internal controls are effective in the future. In addition, any future material weaknesses, or any failure to effectively address a material weakness or other control deficiency or implement required new or improved controls, or difficulties encountered in their implementation, could limit our ability to obtain financing, harm our reputation, disrupt our ability to process key components of our results of operations and financial position timely and accurately and cause us to fail to meet our reporting obligations under rules of the SEC and New York Stock Exchange (NYSE).

If we fail to develop or 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 develop and 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 comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or 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

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opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

To maintain and increase our levels of production, we will need to acquire oil and 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 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 directors, is also a managing director of Lime Rock Partners, and Messrs. Mullins and Adcock, our 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 you.

Under our services agreement with Lime Rock Management and OpCo, each of Lime Rock Management and OpCo receive 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.

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

Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors. 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. 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. Lime Rock Resources, through Fund I, owns an approximate 52.4% limited partner interest in us. 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. Our partnership agreement may not be amended during the subordination period without the approval of our public common unitholders, other than in certain limited circumstances where no unitholder approval is required. However, after the subordination period has ended, our partnership agreement may be amended with the consent of our general partner and the approval of the holders of a majority of our outstanding common units (including common units held by Fund I and its affiliates). Assuming we do not issue any additional common units and Fund I does not transfer its common units, Fund I will have the ability to amend our partnership agreement, including our policy to distribute all of our available cash to our unitholders, without the approval of any other unitholder once the subordination period ends. Furthermore, the goals and objectives of Fund I and our general partner 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.

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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, 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

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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, they cannot remove our general partner without its consent.

The public unitholders will be unable initially to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. 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. Fund I currently owns approximately 52.5% of our outstanding voting units.

Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor business management, so the removal of the general partner because of the unitholder s dissatisfaction with our general partner s performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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 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;

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- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- 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.

Fund I owns an aggregate of approximately 32.2% of our outstanding common units and all of our subordinated units, which convert into common units at the end of the subordination period. 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 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. Fund I owns an aggregate of approximately 32.2% of our outstanding common units and all of our subordinated units. At the end of the subordination period, assuming no additional issuances of common units and that all of the subordinated units are converted into common units, Fund I will own approximately 52.5% 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 will be 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

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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.

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 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 restrict our ability to pay distributions if we do not satisfy the financial and other covenants in the facility.

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

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

If we were treated as a corporation for 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.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders and, therefore, negatively impact the value of an investment in our units. 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 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 federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial interpretation at any time. For example, the Obama Administration and members of Congress have considered substantive changes to the existing federal income tax laws that would affect the tax treatment of or impose additional administrative requirements on publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Although we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted, any such changes could negatively impact the value of an investment in our units. 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 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.

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President Obama s budget proposal for fiscal year 2013 and other recently introduced legislation include proposals that would, if enacted, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

If the IRS contests any of the federal income tax positions we take, the market for our units may be adversely affected, and the costs of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all 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 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.

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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 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. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations 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 respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For 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) 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.

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We will adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders. A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable 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 initially will 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.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal, state and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

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, 2011, our total estimated proved reserves were approximately 28.8 MMBoe, of which approximately 70% were proved developed producing reserves and approximately 15% were proved developed non-producing reserves. 64% of our reserves as measured by volume as of December 31, 2011 were natural gas. As of December 31, 2011, we operated approximately 93% of our proved reserves and produced from approximately 770

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gross (678 net) wells across our operated properties, with an average working interest of approximately 88%. Based on our reserve reports as of December 31, 2011, the estimated decline rate for our existing proved developed producing reserves is approximately 12% per year for 2012 through 2017 and approximately 8% per year thereafter. As of December 31, 2011, approximately 4.4 MMBoe, or approximately 15% of our estimated proved reserves, were proved developed non-producing reserves. Such estimated proved developed non-producing reserves were approximately 48% oil and NGLs and included 196 gross (158 net) recompletion, refracture stimulation and workover projects. In addition, as of December 31, 2011, approximately 4.3 MMBoe, or 15% of our estimated proved reserves, were proved undeveloped reserves. Our proved undeveloped reserves were approximately 64% oil and NGLs and included 214 gross (144 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 Risk Factors Risks Related to Our Business.

The following table shows the estimated net proved oil and natural gas reserves of the Partnership Properties as of December 31, 2011, based on the reserve reports prepared by Miller and Lents, Ltd. (Miller and Lents) and Netherland, Sewell and Associates, Inc. (Netherland Sewell), our independent petroleum engineers, and certain unaudited information regarding such properties.

	Estimated Net Proved Reserves as of December 31, 2011 (1)					
	MBoe	% of Total Reserves	% Proved Developed	% Oil and NGLs	% Operated	Standardized Measure ($ millions)
Permian Basin Region	15,341	53%	79%	60%	93%	$ 231,848
Mid-Continent Region	10,041	35%	94%	0%	92%	67,490
Gulf Coast Region	3,468	12%	88%	30%	100%	42,996
All Regions	28,850	100%	85%	36%	93%	342,334

(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 $96.19/Bbl for NYMEX-WTI oil and $4.12/MMBtu for NYMEX-Henry Hub natural gas for the twelve months ended December 31, 2011. For NGL pricing, a differential is applied to the $96.19/Bbl average trailing twelve-month index price of oil.

Summary of Oil and Natural Gas Properties and Projects

The Permian Basin Region

Approximately 53% of our estimated proved reserves as of December 31, 2011 and approximately 46% of our average daily net production for the period from November 16, 2011 to December 31, 2011 were located in the Permian Basin region. Approximately 60% 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

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over 24 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 83% average working interest across 682 gross (564 net) wells and operate approximately 93% of our properties in the Permian Basin. Our estimated proved reserves for our Permian Basin properties as of December 31, 2011 totaled 15.3 MMBoe and had a standardized measure of $231.8 million, which represented 68% 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 approximately 12% per year over the next five years and approximately 8% thereafter. Based on our reserve report dated December 31, 2011, we expect to spend $26.2 million on recompletions, re-stimulations, workovers and facility upgrades to convert our 2.8 MMBoe of Permian Basin proved developed non-producing reserves to proved developed producing reserves and $98.0 million on drilling to convert our 3.2 MMBoe of Permian Basin proved undeveloped reserves to proved developed producing.

The Mid-Continent Region

Approximately 35% of our estimated proved reserves as of December 31, 2011 and approximately 36% of our average daily net production for the period from November 16, 2011 to December 31, 2011 were located in the Mid-Continent region. Approximately 100% of our estimated net proved reserves in the Mid-Continent region are natural gas. 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 69% average working interest across 150 gross (104 net) wells and operate 92% of our properties in the Mid-Continent region. Our estimated proved reserves for our Mid-Continent region properties as of December 31, 2011 were 10.0 MMBoe and had a standardized measure of $67.5 million, which represented 20% 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 approximately 10% per year over the next five years and 8% per year thereafter. Based on our reserve report dated December 31, 2011, we expect to spend $1.9 million on recompletions and workovers to convert our 1.0 MMBoe of Mid-Continent proved developed non-producing reserves to proved developed producing reserves and $7.5 million on drilling to convert our 0.6 MMBoe of Mid-Continent proved undeveloped reserves to proved developed producing.

The Gulf Coast Region

Approximately 12% of our estimated proved reserves as of December 31, 2011 and approximately 18% of our average daily net production for the period from November 16, 2011 to December 31, 2011 were located in the Gulf Coast region. Approximately 30% 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 an 82% average working interest across 42 gross (35 net) wells and operate 100% of our properties in the Gulf Coast region. Our estimated proved reserves as of December 31, 2011 totaled 3.5 MMBoe and had a standardized measure of $43.0 million as of December 31, 2011, which represented 13% 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 approximately 15% per year over the next five years and 10% per year thereafter. Based on our reserve report dated December 31, 2011, we expect to spend $1.1 million on recompletions and workovers to convert our 0.7 MMBoe of Gulf Coast proved developed non-producing reserves to proved developed producing reserves and $6.2 million on drilling convert our 0.4 MMBoe of Gulf Coast proved undeveloped reserves to proved developed producing.

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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 OpCo s corporate reservoir engineering staff. OpCo maintains internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interacts with OpCo 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 semi-annual basis. Our reserve estimates are evaluated by Miller and Lents, Ltd. (Miller and Lents) and Netherland, Sewell & Associates, Inc. (Netherland Sewell), our independent third-party reserve engineers, or another independent reserve engineering firm, at least annually.

Our internal professional staff works closely with Miller and Lents and Netherland Sewell 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 and Netherland Sewell 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 and Netherland Sewell 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 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, Vice President 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 over 28 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.

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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, OpCo, 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 OpCo, 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 29 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, OpCo, 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 OpCo, 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 30 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.

Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves attributable to the Partnership Properties, and the standardized measure amounts associated with such reserves, as of December 31, 2011, prepared by Miller and Lents and Netherland Sewell, our independent reserve engineers. All of our reserves have been reviewed 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.

		As of December 31, 2011
Reserve Data(1):		
Estimated proved reserves:		
Oil (MBbls)		7,295
NGLs (MBbls)		3,065
Natural gas (MMcf)		110,943
Total estimated proved reserves (MBoe)(2)		28,850
Estimated proved developed reserves:		
Oil (MBbls)		5,275
NGLs (MBbls)		2,334
Natural gas (MMcf)		101,813
Total estimated proved developed reserves (MBoe)(2)		24,578
Estimated proved undeveloped reserves:		
Oil (MBbls)		2,020
NGLs (MBbls)		731
Natural gas (MMcf)		9,130
Total estimated proved undeveloped reserves (MBoe)(2)		4,273
Standardized Measure (in millions)(3)	$	342.3

(1) Our estimated net proved reserves and related standardized measure were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $96.19/Bbl for NYMEX-WTI oil and NGLs and $4.12/MMBtu for NYMEX-Henry Hub natural gas at December 31, 2011. 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-

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the-month oil prices for the prior twelve months. As of December 31, 2011, the relevant average realized prices for oil, natural gas and NGLs were $90.93 per Bbl, $4.10 per Mcf and $51.50 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 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 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 predecessor s proved undeveloped reserve category for the year to date period ended November 15, 2011:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved undeveloped reserves-beginning of year	967	440	4,136	2,096
Transferred to proved developed through drilling	(265)	(81)	(415)	(416)
Increase due to evaluation reassessments and drilling results, net	1,640	456	6,099	3,113
Acquisition of reserves				
Reductions of proved developed reserves aged five or more years				
Proved undeveloped reserves-end of period	2,342	815	9,820	4,793

Our predecessor incurred $9.2 million in capital to convert proved undeveloped reserves to proved developed reserves during the year to date period ended November 15, 2011. No activity occurred in our proved undeveloped reserves from the period November 16 to December 31, 2011.

All of our proved undeveloped reserves as of December 31, 2011 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. Historically, our drilling and development programs were substantially funded from our cash flow from operations. Our expectation is to continue to 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 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

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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, 2011, we were completing production testing on one well. We were not completing, recompleting or conducting a capital workover on any well.

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.

	Partnership(1)				**Predecessor**			
	2011		**2011**		**2010**		**2009**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development wells:								
Productive	0	0	31	17	27	16	31	23
Dry	0	0	0	0	1	1	0	0
Exploratory wells:								
Productive	0	0	0	0	0	0	0	0
Dry	0	0	0	0	0	0	0	0
Total wells:								
Productive	0	0	31	17	27	16	31	23
Dry	0	0	0	0	1	1	0	0
Total	0	0	31	17	28	17	31	23

(1) Reflects our drilling activity for the period from November 16 to December 31, 2011.

Other Exploratory and Development Activities. As of December 31, 2011, we did not have any exploratory activities in progress on our properties.

Productive Wells

The following table sets forth information at December 31, 2011 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	210	186	560	492
Non-operated	44	10	60	14
Total	254	196	620	506

Developed Acreage

The following table sets forth information as of December 31, 2011 relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2011, substantially all of our leasehold acreage was held by production.

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	Developed Acreage	
	Gross (1)	Net (2)
Permian Basin	194,431	122,593
Mid-Continent	22,643	16,331
Gulf Coast	13,758	12,103
Total	230,832	151,027

(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, 2011, we have identified 196 gross (158 net) recompletion, refracture stimulation and workover projects and 214 gross (144 net) proved undeveloped drilling locations on the Partnership Properties. Excluding acquisitions, we anticipate capital expenditures of approximately $20.4 million during the twelve months ending December 31, 2012, including drilling 38 gross (32 net) development wells and executing 31 gross (22 net) recompletions, refracture stimulations and workover projects.

Operations

General

As of December 31, 2011, we operated approximately 93% 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. Pursuant to our services agreement with OpCo and Lime Rock Management, OpCo and Lime Rock Management provide management, administrative and operational services to our general partner and us to manage and operate our business. OpCo 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 the Partnership Properties range from 6% to 54%, resulting in a net revenue interest to us ranging from 2% to 88%, or 65% 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.

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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 March 16, 2012, there were 15,700,074 common units outstanding held by approximately six holders of record, including common units held by Lime Rock Resources.

The daily high and low sales prices (NYSE composite transactions) per common unit for the period from November 11, 2011 (the initial listing date of the units) through December 31, 2011 was $22.39 to $17.03.

We have also issued 6,720,000 subordinated units, for which there is no established trading public trading market. The subordinated units are held by Fund I. Finally, we have issued 22,400 general partner units to LRE GP, LLC.

Cash Distribution to Unitholders

On January 17, 2012, the board of directors of LRE, GP, LLC declared a quarterly cash distribution for the fourth quarter of 2011 of $0.2323 per unit. The distribution represented a proration of our minimum quarterly distribution of $0.4750 per unit for the period from November 17, 2011 through December 31, 2011. The aggregate distribution of $5.2 million was paid on February 14, 2012 to unitholders of record as of the close of business on January 31, 2012.

Cash Distribution Policy

Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ending December 31, 2011, 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

- 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 on our subordinated units 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.

Fund I owns an aggregate of 6,720,000 subordinated units. During the subordination period, the common units will have 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 may be made on the subordinated units. These units are deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions from operating surplus until the common units

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have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash from operating surplus to be distributed on the common units.

The subordination period will extend until the first business day of any quarter after December 31, 2014 that we have 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, provided there are no arrearages in the minimum quarterly distribution on our common units at that time. However, three separate one third tranches of subordinated units may 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, has been earned and paid prior to the applicable date, in each case provided there are no arrearages in the minimum quarterly distribution on our common units at that time.

In addition, the subordination period will end on the first business day after we have earned and paid from operating surplus at least (i) $0.54625 per quarter (115% of the minimum quarterly distribution, which is $2.185 on an annualized basis) on each outstanding common and subordinated unit and the corresponding distributions on our general partner s 0.1% interest and the incentive distribution rights for any four quarter period ending on or after December 31, 2013, or (ii) $0.59375 per quarter (125% of the minimum quarterly distribution, which is $2.375 on an annualized basis) on each outstanding common and subordinated unit and the corresponding distributions on our general partner s 0.1% interest and the incentive distribution rights for any four quarter period, in each case provided there are no arrearages in the minimum quarterly distribution on our common units at that time.

The subordination period will also end, with respect to subordinated units held by any person, upon the removal of our general partner other than for cause if the units held by such person and its affiliates are not voted in favor of such removal and such person is not an affiliate of the successor to the general partner.

When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and all common units thereafter will no longer be entitled to arrearages.

During Subordination Period. Assuming our general partner maintains its 0.1% general partner interest in us, our partnership agreement requires 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 distribute 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 distribute 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 distribute 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 receives a total of $0.54625 per unit for that quarter.

If cash distributions to our unitholders exceed $0.54625 per common unit and subordinated 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 its 0.1% general partner interest. We refer to the additional increasing distributions to our general partner in excess of its 0.1% 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, 2011.

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, 2011 and for the period from November 16 to December 31, 2011 is derived from our audited financial statements. The selected financial data for the period from January 1, 2011 to November 15, 2011 and as of and for the years ended December 31, 2010, 2009, 2008 and 2007 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 November 16 to December 31, 2011	January 1 to November 15, 2011	Year Ended December 31, 2010	Predecessor Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
Statement of Operations Data:						
Revenues:						
Oil sales	$ 6,118	$ 59,605	$ 52,670	$ 34,604	$ 58,852	$ 5,722
Natural gas sales	3,482	35,883	48,088	33,798	100,378	19,714
Natural gas liquids sales	1,567	14,500	14,748	10,617	20,393	367
Realized gain (loss) on commodity derivative instruments	4,015	9,353	48,029	70,902	(2,676)	3,622
Unrealized gain (loss) on commodity derivative instruments	6,664	12,674	(23,964)	(62,375)	117,757	(13,019)
Other income		159	116	24	18	
Total revenues	21,846	132,174	139,687	87,570	294,722	16,406
Operating expenses:						
Lease operating expenses	2,441	21,391	23,804	19,066	18,781	5,587
Production and ad valorem taxes	850	7,763	9,320	6,731	13,899	1,956
Depletion and depreciation	3,923	37,206	55,828	56,349	79,477	11,886
Impairment of oil and gas properties		16,765	11,712		121,561	
Accretion expense	168	1,290	1,366	1,255	691	121
(Gain) loss on settlement of asset retirement obligations		496	(209)	(1,570)	250	
Management fees		5,435	6,104	8,500	8,500	8,521
General and administrative expenses	1,662	5,149	5,293	2,408	2,493	1,086
Total operating expenses	9,044	95,495	113,218	92,739	245,652	29,157
Operating income (loss)	12,802	36,679	26,469	(5,169)	49,070	(12,751)
Other income (expense), net						
Interest income		1	17	87	623	542
Interest expense	(604)	(919)	(3,223)	(1,274)	(2,131)	(792)
Realized loss on interest rate derivative instruments		(574)	(649)	(457)	(71)	
Unrealized gain (loss) on interest rate derivative instruments		441	(248)	95	(709)	
Other income (expense), net	(604)	(1,051)	(4,103)	(1,549)	(2,288)	(250)
Income (loss) before taxes	12,198	35,628	22,366	(6,718)	46,782	(13,001)
Income tax benefit (expense)	(48)	76	(32)	622	(971)	
Net income (loss)	$ 12,150	$ 35,704	$ 22,334	$ (6,096)	$ 45,811	$ (13,001)
General partner s interest in net income	$ 12					
Limited partners interest in net income	$ 12,138					
	$ 0.54					

Net income per limited partner unit (basic and diluted)												
Weighted average number of limited partner units outstanding (basic and diluted)		22,418										
Other Financial Data:												
Adjusted EBITDA	$	10,260	$	79,762	$	119,130	$	113,240	$	133,292	$	12,275

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(in thousands)	Partnership November 16 to December 31, 2011	January 1 to November 15, 2011	Year Ended December 31, 2010	Predecessor Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
Cash Flow Data:						
Net cash provided by operating activities	$ 2,173	$ 84,027	$ 121,269	$ 108,148	$ 139,236	$ (6,437)
Net cash used in investing activities	$ (755)	$ (44,891)	$ (125,846)	$ (25,129)	$ (217,986)	$ (237,865)
Net cash provided by (used in) financing activities	$ 95	$ (38,000)	$ 1,505	$ (118,151)	$ 117,758	$ 224,479
Balance Sheet Data:						
Working capital	$ 23,131	(1)	$ 33,209	$ 57,466	$ 113,846	$ 26,657
Total assets	458,066	(1)	504,622	465,691	593,866	416,436
Total debt	155,800	(1)	27,251	24,150	32,250	11,100
Unitholders Equity/Partners capital	271,503	(1)	426,733	405,646	521,784	379,244

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

Non-GAAP Financial Measures

We include in this report the non-GAAP financial measures Adjusted EBITDA and Distributable Cash Flow and provide reconciliations of these items to net income and net cash provided by operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income (loss):

- *Plus*:
- Income tax expense (benefit);
- Interest expense-net, including realized and unrealized losses on interest rate derivative contracts;
- Depletion and depreciation;
- Accretion of asset retirement obligations;
- Gain (loss) on settlement of asset retirement obligations;
- Unrealized losses on commodity derivative contracts;
- Impairment of oil and natural gas properties; and

- Other non-recurring items that we deem appropriate.

- *Less*:
- Interest income;
- Unrealized gains on commodity derivative contracts; and
- Other non-recurring items that we deem appropriate.

We define Distributable Cash Flow as Adjusted EBITDA less income tax expense; cash interest expense, net; realized losses on interest rate swaps; and estimated maintenance capital expenditures.

Adjusted EBITDA and Distributable Cash Flow are used as supplemental financial measures by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess:

- our operating performance as compared to that of other companies and partnerships in our industry, without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders; and
- our ability to incur and service debt and fund capital expenditures.

Adjusted EBITDA and Distributable Cash Flow should not be considered an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA or Distributable Cash Flow in the same manner. The following table presents a reconciliation of Adjusted EBITDA to

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net income and net cash provided by operating activities, our most directly comparable GAAP financial performance and liquidity measures, for each of the periods indicated.

Reconciliation of Adjusted EBITDA to Net Income

(in thousands)	Partnership November 16 to December 31, 2011	January 1 to November 15, 2011	Year Ended December 31, 2010	Predecessor Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
Net income (loss)	$ 12,150	$ 35,704	$ 22,334	$ (6,096)	$ 45,811	$ (13,001)
Income tax expense (benefit)	48	(76)	32	(622)	971	
Interest expense-net, including realized and unrealized losses on interest rate derivative instruments	604	1,052	4,120	1,636	2,911	792
Depletion and depreciation	3,923	37,206	55,828	56,349	79,477	11,886
Accretion of asset retirement obligations	168	1,290	1,366	1,255	691	121
Amortization of equity awards	31					
Gain (loss) on settlement of asset retirement obligations		496	(209)	(1,570)	250	
Unrealized losses on commodity derivative instruments			23,964	62,375		13,019
Impairment of oil and natural gas properties		16,765	11,712		121,561	
Interest income		(1)	(17)	(87)	(623)	(542)
Unrealized gain on commodity derivative instruments	(6,664)	(12,674)			(117,757)	
Adjusted EBITDA	$ 10,260	$ 79,762	$ 119,130	$ 113,240	$ 133,292	$ 12,275

Reconciliation of Adjusted EBITDA to Net Cash Provided by Operating Activities

(in thousands)	Partnership November 16 to December 31, 2011	January 1 to November 15, 2011	Year Ended December 31, 2010	Predecessor Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
Net cash provided by (used in) operating activities	$ 2,173	$ 84,027	$ 121,269	$ 108,148	$ 139,236	$ (6,437)
Change in working capital	7,485	(5,622)	(5,888)	4,187	(8,443)	18,499
Interest expense-net	554	1,433	3,717	1,527	1,528	213
	48	(76)	32	(622)	971	

Income tax expense (benefit)						
Adjusted EBITDA	$ 10,260	$ 79,762	$ 119,130	$ 113,240	$ 133,292	$ 12,275

Distributable Cash Flow

The following table presents a reconciliation of Distributable Cash Flow to Adjusted EBITDA for the period from November 16 to December 31, 2011. Adjusted EBITDA is reconciled to net income and net cash provided by operating activities, our most directly comparable GAAP performance and liquidity measures, above.

Adjusted EBITDA	$ 10,260
Income tax expense	(48)
Cash Interest expense	
Estimated maintenance capital (1)	(2,250)
Distributable Cash Flow	$ 7,962

(1) Estimated annual maintenance capital was $18 million for 2011. Amount represents pro-rated capital for the 46 day period from November 16 to December 31, 2011.

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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, 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

We are a Delaware limited partnership formed in April 2011 by 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. 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 or predecessor refer collectively to LRR A, LRR B and LRR C. Fund I is managed by Lime Rock Management and pays a management fee to Lime Rock Management. In addition, Fund I also receives administrative services from OpCo.

In connection with the completion of our IPO on November 16, 2011, pursuant to a contribution, conveyance and assumption agreement, we acquired specified oil and natural gas properties and related net profits interests and operations and certain commodity derivative contracts (the Partnership Properties) owned by LRR A, LRR B, and LRR C. The underwriters partially exercised their option to purchase additional units and on December 14, 2011, we issued an additional 1,200,000 units to the public. The net proceeds from the exercise of the underwriters option to purchase additional common units was used to pay additional cash consideration for the properties purchased from Fund I in connection with the IPO and to make additional distributions to Fund I.

Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and the assumption of $27.3 million of LRR A s indebtedness. For further discussion regarding our IPO, please see Note 1 to the consolidated/combined financial statements included in this report.

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 874 gross (702 net) producing wells, of which we owned an approximate 80% average working interest. As of December 31, 2011, our total estimated proved reserves were approximately 28.8 MMBoe, of which approximately 36% were oil and NGLs as measured by volume, approximately 70% were proved developed producing and approximately 15% were proved developed non-producing. As of December 31, 2011, our estimated proved reserves had a standardized measure of $342.3 million.

Of our total estimated proved reserves as of December 31, 2011, 15.3 MMBoe, or approximately 53%, are located in the Permian Basin region; 10.0 MMBoe, or approximately 35%, are located in the Mid-Continent region; and 3.5 MMBoe, or approximately 12%, are located in the Gulf Coast region.

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;

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- lease operating expenses;
- general and administrative expenses;
- net cash provided by operating activities;
- 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, or API, gravity and (2) the oil s percentage of sulfur content by weight. In general, lighter oil (with higher API gravity) produces a larger number of lighter products, such as gasoline, which have higher resale value, and, therefore, normally sells at a higher price than heavier oil. Oil with low sulfur content (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. 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 CO2 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.

NGLs. 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, 2011, the NYMEX-WTI oil price ranged from a high of $113.93 per Bbl to a low of $75.67 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $4.92 per MMBtu to a low of $2.83 per MMBtu. For the five years ended December 31, 2011, the NYMEX-WTI oil price ranged from a high of $145.29 per Bbl to a low of $31.41 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $13.31 per MMBtu to a low of $1.88 per MMBtu. As of March 26, 2012, the NYMEX-WTI oil spot price was $107.03 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.13 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, 2011, 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 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.

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General and Administrative Expenses. We have entered into a services agreement with Lime Rock Management and OpCo 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 OpCo 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 OpCo, 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

Adjusted EBITDA and Distributable Cash Flow are used as supplemental financial measures by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess:

- our operating performance as compared to that of other companies and partnerships in our industry, without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders; and
- our ability to incur and service debt and fund capital expenditures.

Adjusted EBITDA and Distributable Cash Flow should not be considered an alternative to net income, operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA or 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 2012 Outlook

We expect to spend approximately $21.2 million of total capital expenditures on the development of our oil and natural gas properties in 2012, including approximately $18.0 million of maintenance capital expenditures. Maintenance capital expenditures represent our estimate of the amount of capital required on average per year to maintain our production over the long term. We expect to spend the remaining $3.2 million of estimated expenditures primarily on projects designed to reduce operating costs and potentially growth capital. The estimated capital expenditures for 2012 do not include any amounts for acquisitions of oil and natural gas properties.

The estimate of 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.

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 Risk Factors.

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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 2015.

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

	Partnership	Predecessor		
	November 16 to December 31, 2011	January 1 to November 15, 2011	Year ended December 31, 2010	2009
Revenues (in thousands):				
Oil sales	$ 6,118	$ 59,605	$ 52,670	$ 34,604
Natural gas sales	3,482	35,883	48,088	33,798
Natural gas liquids sales	1,567	14,500	14,748	10,617
Realized gain (loss) on commodity derivative instruments	4,015	9,353	48,029	70,902
Unrealized gain (loss) on commodity derivative instruments	6,664	12,674	(23,964)	(62,375)
Other income		159	116	24
Total revenues	21,846	132,174	139,687	87,570
Expenses (in thousands):				
Lease operating expense	2,441	21,391	23,804	19,066
Production and ad valorem taxes	850	7,763	9,320	6,731
Depletion and depreciation	3,923	37,206	55,828	56,349
Impairment of oil and natural gas properties		16,765	11,712	
Management fees		5,435	6,104	8,500
General and administrative expense	1,662	5,149	5,293(1)	2,408
Interest expense	604	919	3,223	1,274
Realized loss on interest rate derivative instruments		574	649	457
Production: (2), (3)				
Oil (MBbls)	65	657	698	602
Natural gas (MMcf)	1,038	8,606	11,287	9,076
NGLs (MBbls)	27	269	376	363
Total (MBoe)	265	2,360	2,955	2,478
Average net production (Boe/d)	5,761	7,398	8,096	6,788

(1) General and administrative expenses for the year ended December 31, 2010 include a $2.5 million finder s fee incurred in connection with the Potato Hills acquisition.

(2) The Red Lake area constituted approximately 31% of our estimated proved reserves as of December 31, 2011. Our production from the Red Lake area was 79 MBoe for the period from November 16 to December 31, 2011. Our predecessor s production from the Red Lake area was 473, 518 and 367 MBoe for the period from January 1 to November 15, 2011 and the years ended December 31, 2010 and 2009, respectively.

(3) The Potato Hills field, which our predecessor acquired in February 2010, constituted approximately 29% of our estimated proved reserves as of December 31, 2011. Our production from the Potato Hills field was 72 MBoe for the period from November 16 to December 31, 2011. Our predecessor s production from the

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Potato Hills field was 527 and 614 MBoe for the period from January 1 to November 15, 2011 and the year ended December 31, 2010, respectively.

	Partnership November 16 to December 31, 2011	Predecessor January 1 to November 15, 2011	Year ended December 31, 2010	2009
Average sales price:				
Oil (per Bbl):				
Sales price	$ 94.12	$ 90.72	$ 75.46	$ 57.48
Effect of realized commodity derivative instruments (1)	11.03	(10.66)	23.15	61.18
Realized sales price	$ 105.15	$ 80.06	$ 98.61	$ 118.66
Natural gas (per Mcf):				
Sales price	$ 3.35	$ 4.17	$ 4.26	$ 3.72
Effect of realized commodity derivative instruments(1)	3.20	1.92	2.82	3.75
Realized sales price	$ 6.55	$ 6.09	$ 7.08	$ 7.47
NGLs (per Bbl)				
Sales price	$ 58.04	$ 53.90	$ 39.22	$ 29.25
Effect of realized commodity derivative instruments(1)	(0.93)	(0.65)		
Realized sales price	$ 57.11	$ 53.25	$ 39.22	$ 29.25
Average unit costs per Boe:				
Lease operating expenses	$ 9.21	$ 9.06	$ 8.06	$ 7.70
Production and ad valorem taxes	$ 3.21	$ 3.29	$ 3.15	$ 2.72
Management fees	$	$ 2.30	$ 2.07	$ 3.43
General and administrative expenses	$ 6.27	$ 2.18	$ 1.79	$ 0.97
Depletion and depreciation	$ 14.80	$ 15.76	$ 18.89	$ 22.74

(1) Realized gains (losses) on commodity derivative instruments were $15.15 per Boe for the period from November 16 to December 31, 2011 and $3.96 per Boe for the period from January 1 to November 15, 2011. Realized gains (losses) on commodity derivative instruments were $16.25 and $28.61 per Boe, for the years ended December 31, 2010 and 2009, respectively.

Partnership s Results of Operations

We completed our IPO on November 16, 2011 with net assets of $386.4 million contributed to us by Fund I and included in our consolidated financial statements at Fund I s book value as a transaction between entities of common control. The book value of net assets we received primarily includes $400.1 million of cost basis of oil and natural gas properties, net derivative instruments of $36.2 million, $27.3 million of debt assumed from Fund I and asset retirement obligations of $22.7 million. Our operating results for the period from November 16 to December 31, 2011 are presented below.

Period from November 16 to December 31, 2011

We recorded net income of $12.1 million during the period from November 16 to December 31, 2011. This net income was primarily driven by total revenues of $21.8 million offset by lease operating expenses of $2.4 million, production and ad valorem taxes of $0.8 million, depletion and depreciation of $3.9 million and general and administrative expenses of $1.7 million.

Sales Revenues. Sales revenues of $11.2 million for the period consisted of oil sales of $6.1 million, natural gas sales of $3.5 million and NGL sales of $1.6 million. Our production volumes for the period included 92 MBbls of oil and NGLs and 1,038 MMcf of natural gas, or 2,000 Bbl/d of oil and NGLs and 22,565 Mcf/d of natural gas. On an equivalent basis, production for the period was 265 MBoe, or 5,761 Boe/d.

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Our average sales price per Bbl for oil and NGLs, excluding the effect of commodity derivative contracts, for the period was $94.12 and $58.04, respectively. Our average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, was $3.35.

During the third week in February 2012 and through the second week in March 2012, approximately 1,515 Bbls/d and 1.7 MMcf/d of our Red Lake field production was entirely shut-in due to a compression system upgrade at the gas plant that processes our Red Lake field natural gas. The upgrade was initially expected to last 7 days, but experienced delays and took 21 days to complete. We are currently producing 1,900 Boe per day, which is approximately 105% of pre-curtailment daily production volumes.

Relating to the previously disclosed Pecos Slope field curtailment, approximately 1.3 MMcf/d of production was curtailed in January and February 2012 due to the gas containing a nitrogen percentage greater than our gas purchaser s specification. Beginning in March 2012, the curtailment was reduced to approximately 0.9 MMcf/d and is expected to remain at this level until the field-wide nitrogen rejection facility is installed. The cumulative curtailment from January to September 2012, on an annualized basis, represents approximately 125 Boe per day. Full restoration of production is expected to occur in October 2012 after a field-wide nitrogen rejection facility is installed by the gas gathering company that gathers and compresses our natural gas in the area. The actual timing and amount of resumed production may differ from these estimates.

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 period of approximately $10.7 million, which is comprised of a realized gain of approximately $4.0 million and an unrealized gain of approximately $6.7 million.

Lease Operating Expenses. Our lease operating expenses were approximately $2.4 million, or $9.21 per Boe, for the period. The per Boe amount is consistent with our predecessor s rate for the remainder of 2011.

Production and Ad Valorem Taxes. Our production and ad valorem taxes were approximately $0.8 million, or $3.21 per Boe, for the period. The per Boe amount is consistent with our predecessor s rate for the remainder of 2011. Production taxes accounted for approximately $0.7 million and ad valorem taxes for $0.1 million of the total taxes recorded.

Depletion and Depreciation. Our depletion and depreciation expense was approximately $3.9 million, or $14.80 per Boe, for the period.

Impairment of Oil and Natural Gas Properties. We did not record any impairment charges during the period.

General and Administration Expenses. Our general and administrative expenses were approximately $1.7 million, or $6.27 per Boe, for the period. The higher per Boe rate than our predecessor is primarily driven by additional expenses related to us being a public company.

Interest Expenses. Our interest expense is comprised of interest on our credit facility and amortization of debt issuance costs. Interest expense was approximately $0.6 million for the period.

Predecessor Results of Operations

Factors Affecting the Comparability of the Historical Financial Results of Our Predecessor

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

- The following acquisitions by our predecessor:

- the Potato Hills acquisition for a purchase price of approximately $104.0 million in February 2010;

- the acquisition of interests in 30 producing oil and natural gas wells located in Texas for a purchase price of approximately $7.5 million in August 2010;

- the acquisition of additional interests in producing oil and natural gas wells located in New Mexico for a purchase price of approximately $1.8 million in October 2010; and

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• the acquisition of additional interests in producing oil and natural gas wells located in Texas for a purchase price of approximately $6.1 million in December 2009.

• The following divestiture by our predecessor:

• the divestiture of interests in 17 producing oil and natural gas wells located in New Mexico for approximately $14.3 million in September 2010.

• The 2011 comparison only includes the period up to November 15, 2011 (the date prior to the IPO)

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

Period from January 1 to November 15, 2011 Compared to the Year Ended December 31, 2010

Our predecessor recorded net income of approximately $35.7 million for the period from January 1 to November 15, 2011 compared to $22.3 million for the year ended December 31, 2010. This increase in net income was primarily driven by an increase in gains on derivative instruments.

Sales Revenues. Revenues from oil, NGLs and natural gas sales for the period from January 1 to November 15, 2011 were $110.0 million compared to $115.5 million for the year ended December 31, 2010. The decrease in revenues was primarily due to a decline in natural gas sales to $35.9 million for the period from January 1 to November 15, 2011 from $48.1 million for the year ended December 31, 2010. This decline was primarily driven by lower natural gas prices in the 2011 period. Oil sales increased to $59.6 million for the period from January 1 to November 15, 2011 from $52.7 million for the year ended December 31, 2010 primarily due to increased oil prices during the period. Natural gas sales were relatively flat between periods.

Our predecessor s production volumes for the period from January 1 to November 15, 2011 included 926 MBbls of oil and NGLs and 8,606 MMcf of natural gas, or 2,903 Bbl/d of oil and NGLs and 26,978 Mcf/d of natural gas. On an equivalent net basis, production for the period from January 1 to November 15, 2011 was 2,360 MBoe, or 7,398 Boe/d. In comparison, our predecessor s production volumes for the year ended December 31, 2010 included 1,074 MBbls of oil and NGLs and 11,287 MMcf of natural gas, or 2,942 Bbl/d of oil and NGLs and 30,923 Mcf/d of natural gas. On an equivalent net basis, production for the year ended December 31, 2010 was 2,955 MBoe, or 8,096 Boe/d.

Our predecessor s average sales price per Bbl for oil and NGLs, excluding the effect of commodity derivative contracts, for the period from January 1 to November 15, 2011 was $90.72 and $53.90, respectively, compared with $75.46 and $39.22, for the year ended December 31, 2010, respectively. Similarly, our predecessor s average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, for the period from January 1 to November 15, 2011 was $4.17 compared with $4.26 for the year ended December 31, 2010.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, our predecessor recorded a gain from its commodity hedging program for the period from January 1 to November 15, 2011 of approximately $22.1 million, which is comprised of a realized gain of approximately $9.4 million and an unrealized gain of approximately $12.7 million. For the year ended December 31, 2010, our predecessor recorded a net gain of approximately $24.0 million, which is comprised of a realized gain of approximately $48.0 million, partially offset by an unrealized loss of approximately $24.0 million.

Lease Operating Expenses. Our predecessor s lease operating expenses were approximately $21.4 million for the period from January 1 to November 15, 2011 compared to approximately $23.8 million for the year ended December 31, 2010. On a per Boe basis, our predecessor s unit lease operating expenses increased to $9.06 per Boe for the period from January 1 to November 15, 2011 compared to $8.06 per Boe for the year ended December 31, 2010 primarily due to new wells coming online at the Red Lake field and increased saltwater disposal costs at the Red Lake and Coral Canyon fields. During the third quarter of 2011, our predecessor invested capital to help reduce saltwater disposal costs.

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Production and Ad Valorem Taxes. Production and ad valorem taxes were approximately $7.8 million for the period from January 1 to November 15, 2011 compared to approximately $9.3 million for the year ended December 31, 2010. The variance is primarily due to changes in the estimates of the appraisals on which our predecessor s property taxes were calculated. On a per Boe basis, production and ad valorem taxes were $3.29 per Boe for the period from January 1 to November 15, 2011 compared to $3.15 per Boe for the year ended December 31, 2010.

Depletion and Depreciation Expenses. Our predecessor s depletion and depreciation expenses were approximately $37.2 million, or $15.76 per Boe, for the period from January 1 to November 15, 2011 compared to approximately $55.8 million, or $18.89 per Boe, for the year ended December 31, 2010. The overall decrease was primarily a result of the 2010 impairment described below and the decline in commodity prices in the first quarter of 2010.

Impairment of Oil and Natural Gas Properties. Our predecessor recorded an impairment of approximately $16.8 million in the period from January 1 to November 15, 2011 due to a decline in natural gas prices during the period. An impairment of $11.7 million was recorded during the year ended December 31, 2010 due to a decline in commodity prices in the first quarter of 2010.

Management Fees. Our predecessor incurs a management fee paid to Lime Rock Management in addition to the direct general and administrative expenses it incurs. The management fee is determined by a formula based on the predecessor s limited partners invested capital or the equity capital commitment in Fund I. The predecessor s management fees were approximately $5.4 million for the period from January 1 to November 15, 2011 compared to approximately $6.1 million for the year ended December 31, 2010.

General and Administrative Expenses. Our predecessor s general and administrative expenses were approximately $5.1 million for the period from January 1 to November 15, 2011 compared to approximately $5.3 million for the year ended December 31, 2010. The 2010 amount included a $2.5 million finder s fee incurred in connection with the Potato Hills acquisition in 2010 which was offset by transactions costs associated with our IPO. General and administrative expenses, on a per Boe basis, were $2.18 per Boe for the period from January 1 to November 15, 2011 compared to $1.79 per Boe for the year ended December 31, 2010.

Interest Expense. Our predecessor s interest expense is comprised of interest on its credit facility, debt issuance and financing costs, and realized gains (losses) on its interest rate derivative instruments. Interest expense for the period from January 1 to November 15, 2011 was approximately $1.5 million compared to approximately $3.9 million for the year ended December 31, 2010. This decrease was primarily due the refinancing of the credit facility in 2010.

Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009

Our predecessor recorded net income of approximately $22.3 million for the year ended December 31, 2010 compared to a net loss of $6.1 million for the year ended December 31, 2009. This increase in net income was primarily driven by an increase in revenues as described below, including an increase in gains on derivative instruments partially offset by an increase in operating costs, reflecting the change in size of operations during the year ended December 31, 2010.

Sales Revenues. Revenues from oil, NGLs and natural gas sales for the year ended December 31, 2010 were $115.5 million as compared to $79.0 million for the year ended December 31, 2009. The increase in revenues was due to an increase in the sale of oil, NGLs and natural gas of $52.7 million, $14.7 million and $48.1 million for the year ended December 31, 2010 as compared to $34.6 million, $10.6 million and $33.8 million for the year ended December 31, 2009. The overall increase in revenues was primarily driven by increases in commodity sales prices and our predecessor s production volumes, including the impact of the Potato Hills acquisition, which closed in February 2010 and resulted in increases in revenues of $15.0 million for the year ended December 31, 2010.

Our predecessor s production volumes for the year ended December 31, 2010 included 1,074 MBbls of oil and NGLs and 11,287 MMcf of natural gas, or 2,942 Bbl/d of oil and NGLs and 30,923 Mcf/d of natural gas. On an equivalent net basis, production for the year ended December 31, 2010 was 2,955 MBoe, or 8,096 Boe/d. In

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comparison, our predecessor s production volumes for the year ended December 31, 2009 included 965 MBbls of oil and NGLs and 9,076 MMcf of natural gas, or 2,643 Bbl/d of oil and NGLs and 24,866 Mcf/d of natural gas. On an equivalent net basis, production for the year ended December 31, 2009 was 2,478 MBoe, or 6,788 Boe/d. The primary driver behind the increase in overall production volumes was the Potato Hills acquisition completed in February 2010.

Our predecessor s average sales price per Bbl for oil and NGLs, excluding the effect of commodity derivative contracts, for the year ended December 31, 2010 was $75.46 and $39.22, respectively, compared with $57.48 and $29.25, respectively, for the year ended December 31, 2009. Similarly, our predecessor s average sales price per Mcf of natural gas, excluding the effect of commodity derivative contracts, for the year ended December 31, 2010 was $4.26 compared with $3.72 per Mcf for the year ended December 31, 2009.

Effects of Commodity Derivative Contracts. Due to changes in oil and natural gas prices, our predecessor recorded a net gain from its commodity hedging program for the year ended December 31, 2010 of approximately $24.0 million, which is composed of a realized gain of approximately $48.0 million, partially offset by an unrealized loss of approximately $24.0 million. For the year ended December 31, 2009, our predecessor recorded a net gain from its commodity hedging program of approximately $8.5 million, consisting of a realized gain of approximately $70.9 million, partially offset by an unrealized loss of approximately $62.4 million.

Lease Operating Expenses. Our predecessor s lease operating expenses were approximately $23.8 million for the year ended December 31, 2010 as compared to $19.1 million for the year ended December 31, 2009. The increase in lease operating expenses was primarily a result of our predecessor s increased production volumes described above and $3.4 million in additional lease operating expenses as a result of the properties acquired in the Potato Hills acquisition. On a per Boe basis, our predecessor s unit lease operating expenses increased to $8.06 per Boe for the year ended December 31, 2010 from approximately $7.70 per Boe for the year ended December 31, 2009. The increased expenses were partially offset by the increased production volumes.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased to approximately $9.3 million for the year ended December 31, 2010 compared to approximately $6.7 million for the year ended December 31, 2009 primarily due to an increase in revenues discussed above. On a per Boe basis, production and ad valorem taxes increased to $3.15 per Boe for the year ended December 31, 2010 as compared to $2.72 per Boe for the year ended December 31, 2009.

Depletion and Depreciation Expenses. Our predecessor s depletion and depreciation expenses were approximately $55.8 million, or $18.89 per Boe, for the year ended December 31, 2010 as compared to $56.3 million or $22.74 per Boe for the year ended December 31, 2009. The overall decrease was primarily a result of the 2010 impairment described below and the decline in commodity prices in the first quarter of 2010.

Impairment of Oil and Natural Gas Properties. An impairment of $11.7 million was required during the year ended December 31, 2010 due to a decline in commodity prices in the first quarter of 2010. No impairment was required in 2009.

Management Fees. Our predecessor incurs a management fee paid to Lime Rock Management in addition to the direct general and administrative expenses it incurs. The management fee is determined by a formula based on the predecessor s limited partners invested capital or the equity capital commitment in Fund I. The predecessor s management fees were approximately $6.1 million for the year ended December 31, 2010 compared to approximately $8.5 million for the year ended December 31, 2009. The overall decrease of $2.4 million was primarily a result of changing the formula based on equity capital commitments to invested capital due to meeting certain requirements as outlined in the predecessor s partnership agreements with its limited partners.

General and Administrative Expenses. Our predecessor s general and administrative expenses were approximately $5.3 million for the year ended December 31, 2010 as compared to $2.4 million for the year ended December 31, 2009. The increase was primarily driven by a $2.5 million finder s fee incurred in connection with the Potato Hills acquisition in 2010. General and administrative expenses, on a per Boe basis, increased in 2010 for the reasons just discussed, but were partially decreased as a function of the higher production volumes. The general and

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administrative expenses per Boe were $1.79 for the year ended December 31, 2010 and $0.97 per Boe for the year ended December 31, 2009.

Interest Expense. Our predecessor s interest expense is comprised of interest on its credit facility, debt issuance and financing costs, and realized gains (losses) on its interest rate derivative instruments. The interest expense was $3.9 million for the year ended December 31, 2010 as compared to $1.7 million for the year ended December 31, 2009. This increase was primarily due to increased borrowings of $3.1 million and the refinancing of the credit facility.

Liquidity and Capital Resources

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

Our primary sources of liquidity and capital resources are cash flows generated by operating activities and borrowings under our credit facility. We may issue additional equity and debt as needed.

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

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 plan to reinvest a sufficient amount of our cash flow to fund our exploitation and development capital expenditures in order to maintain our production, and we plan 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 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

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to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our credit facility. 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.

As of December 31, 2011, we had borrowing capacity of $94.2 million under our $500 million revolving credit facility ($250 million borrowing base less $155.8 million of outstanding borrowings). Based upon current oil and natural gas price expectations and our commodity derivatives positions for the year ending December 31, 2012, which cover 84% of our estimated production from total proved developed producing reserves, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility will provide us sufficient working capital to meet our total planned 2012 capital expenditures of approximately $21.2 million, of which approximately $18.0 million is maintenance capital and planned 2012 annualized cash distributions of approximately $42.6 million. Our board of directors determines our distribution each quarter and there is no guarantee that the board will maintain or increase our current quarterly distribution of $0.4750 per unit.

Capital Expenditures

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. We have estimated our maintenance capital expenditures to be approximately $18.0 million in 2012.

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 2012, 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.

The amount and timing of our capital expenditures is largely discretionary and within our general partner s control, with the exception of certain projects managed by other operators. If oil and natural gas prices decline below levels we deem acceptable, our general partner may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside of our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and labor crews. Based on our current oil and natural gas price expectations, we anticipate that our cash flow from operations and available borrowing capacity under our credit facility will exceed our planned capital expenditures and other cash requirements for 2012. 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.

Credit Facility

In connection with our IPO, we, as guarantor and our wholly owned subsidiary, LRE Operating, LLC, as borrower, entered into a senior secured revolving credit facility. The credit facility is a five-year, $500 million revolving credit facility with a current borrowing base of $250 million.

Our credit facility is reserve-based, and we are permitted to borrow under our credit facility 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

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our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. Our borrowing base is subject to 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 new credit facility as a result of (i) a subsequent borrowing base redetermination or (ii) an unwillingness or inability on the part of our lenders to meet their funding obligations.

A future decline in commodity prices could result in a redetermination that lowers our borrowing base in the future and, in such case, 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 facility. 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 facility after giving effect to such distribution.

Borrowings under the credit facility 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 LRE Operating, LLC and any future guarantor subsidiaries and all of our other assets including personal property. Additionally, borrowings under the credit facility will bear interest, at our 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 would be subject to a margin that varies from 0.75% to 1.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

Our credit facility requires maintenance of a ratio of Total Debt (as such term is defined in the credit facility) 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 facility 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, plus reasonable one-time fees, charges and expenses related to our IPO, our acquisition of the Partnership Properties and the closing of the credit facility or other start up activities, minus all noncash income.

Additionally, the credit facility contains various covenants and restrictive provisions which limit our 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 facility include, but are not limited to, failure to make payments when due; any material inaccuracy in the representations and warranties of LRE Operating; 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 facility, together with accrued interest, could be declared immediately due and payable. As of December 31, 2011, we are in compliance with our covenants.

At December 31, 2011, we had approximately $155.8 million of outstanding borrowings under our credit facility and available borrowing capacity of approximately $94.2 million.

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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 and collars in place as of December 31, 2011. The weighted average price is based on the swap price for oil, NGL and natural gas swaps and the floor price of oil and natural gas collars. We use swaps and collars 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 and natural gas production. These transactions are settled based upon the NYMEX-WTI price of oil and NYMEX-Henry Hub price of natural gas on the average of the three final trading days of the month, with settlement occurring on the fifth day of the production month.

	Oil (NYMEX-WTI) Weighted Average		NGL (NYMEX-WTI) Weighted Average		Natural Gas (NYMEX-Henry Hub) Weighted Average	
Term	**$/Bbl**	**Bbls/d**	**$/Bbl**	**Bbls/d**	**$/Mmbtu**	**Mmbtu/d**
2012	$ 102.20	688	$ 49.92	450	$ 5.56	18,047
2013	$ 101.30	793	$		$ 5.59	15,774
2014	$ 100.01	680	$		$ 5.76	13,992
2015	$ 98.90	602	$		$ 5.96	12,592

We did not have any oil and natural gas basis swaps in place as of December 31, 2011; however, subsequent to December 31, 2011, we entered into basis swaps that are designed to effectively fix a price differential between NYMEX-Henry Hub price and the index price at which the physical natural gas is sold. For further discussion of those swaps entered into subsequent to December 31, 2011, please see Note 14 to the consolidated/combined financial statements.

Cash Flows

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

	Partnership	Predecessor		
	November 16 to December 31, 2011	January 1 to November 15, 2011	Year ended December 31, 2010	2009
Net cash provided by (used in):				
Operating activities	$ 2,173	$ 84,027	$ 121,269	$ 108,148
Investing activities	(755)	(44,891)	(125,846)	(25,129)
Financing activities	95	(38,000)	1,505	(118,151)

Operating Activities.

Partnership. Net cash provided by operating activities was approximately $2.2 million, which reflected our activity from November 16 to December 31, 2011.

Predecessor. Net cash provided by operating activities was approximately $84.0 million, $121.3 million and $108.1 million for the period from January 1 to November 15, 2011 and the years ended December 31, 2010 and 2009, respectively. Revenues fluctuated during the periods presented primarily due to the volatility of commodity prices, and therefore our predecessor s net cash provided by operating activities fluctuated during those periods. Cash provided by operating activities is impacted by the prices received for oil and natural gas sales and levels of production volumes.

Our working capital totaled $23.1 million at December 31, 2011. Our predecessor s working capital totaled $33.2 million at December 31, 2010. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $1.5 million at December 31, 2011 and our predecessor s cash balances totaled $12.5 million at December 31, 2010.

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Investing Activities.

Partnership. Net cash used in investing activities was approximately $0.8 million, which primarily represented additions to our property and equipment balances during the period from November 16 to December 31, 2011.

Predecessor. Net cash used in investing activities by our predecessor was approximately $44.9 million, $125.8 million and $25.1 million for the period from January 1 to November 15, 2011 and the years ended December 31, 2010 and 2009, respectively. The increased amount of cash used in investing activities in the year ended December 31, 2010 was principally due to the acquisitions of oil and natural gas properties, which included the Potato Hills acquisition in February 2010.

Financing Activities.

Partnership. Cash flows from financing activities of $0.1 million for the period from November 16 to December 31, 2011 primarily relates to our IPO. We received $188.5 million of net proceeds from our IPO, $155.8 million from borrowings under our revolving credit facility and $0.4 million from our general partner. We distributed $311.2 million to Fund I as consideration for the Partnership Properties and paid $27.3 million of the debt assumed from LRR A. We also paid IPO transaction costs of $4.7 million and deferred financing costs of $1.4 million.

Predecessor. Net cash provided by (used in) financing activities by our predecessor was approximately $(38.0) million, $1.5 million and $(118.2) million for the period from January 1 to November 15, 2011 and the years ended December 31, 2010 and 2009, respectively. In 2011, the cash used in financing activities consisted of distributions of approximately $43.4 million offset by capital contributions of $5.4 million. For 2010, the cash provided by financing activities primarily related to $129.0 million of capital contributions for acquisitions, debt borrowings of $8.6 million offset by distributions of $120.9 million, return of capital of $9.3 million and debt repayments of $5.5 million. For 2009, the cash used in financing activities primarily related to $124.0 million of distributions, $3.8 million of return of capital, debt repayments of $9.0 million offset by capital contributions of $17.8 million.

We expect to spend approximately $21.2 million in total capital expenditures in 2012, of which approximately $18.0 million represents maintenance capital expenditures on the development of our oil and natural gas properties in 2012.

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.4750 per unit per quarter ($1.90 per unit on an annualized basis). Based on the number of common units, subordinated units and general partner units outstanding as of March 16, 2012, distributions to all of our unitholders at the minimum quarterly distribution rate for 2012 would total approximately $10.7 million.

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 2012 though external financing sources, including borrowings under our revolving credit facility and the issuance of debt and equity securities.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2011 is provided in the following table (in thousands).

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	Obligations Due in Period													
Contractual Obligation		**2012**		**2013**		**2014**		**2015**		**2016**		**Thereafter**		**Total**
Long-term debt (1)	$		$		$		$		$	155,800	$		$	155,800
Interest on long-term debt(2)		4,927		4,927		4,927		4,927		2,463				22,171
Total	$	4,927	$	4,927	$	4,927	$	4,927	$	158,263	$		$	177,971

(1) Represents amounts outstanding under our revolving credit facility as of December 31, 2011. The total balance of our revolving credit facility will mature in July 2016.

(2) Based upon the weighted average interest rate of approximately 2.86 % under the credit facility at December 31, 2011 and an unused commitment fee of 0.50% on $94.2 million.

The table above excludes amounts associated with our oil and natural gas property asset retirement obligations. As of December 31, 2011, approximately $23.1 million of such obligations were recorded as liabilities, $0.4 million of which was reflected as current liabilities.

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.

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.

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. and Netherland, Sewell & Associates, Inc., 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, 2011 included in this report are based on reserve reports prepared by Miller and Lents, Ltd. and Netherland, Sewell & Associates, Inc.

We prepare our reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. Our independent engineering firm adheres 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.

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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 New York Mercantile Exchange (NYMEX) forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. 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.

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 period from January 1 to November 15, 2011, our predecessor recorded a non cash impairment charge of approximately $16.8 million. For the year ended December 31, 2010, our predecessor recorded a non cash impairment charge of approximately $11.7 million primarily associated with proved oil and natural gas properties related to unfavorable market conditions. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair-value measurement. The charges are included in impairment of oil and natural gas properties in our condensed/combined statements of operations. Our predecessor

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recorded no impairment charge of proved oil and natural gas properties for the year ended December 31, 2009. We recorded no impairment charge of proved oil and natural gas properties for the period from November 16 to December 31, 2011. If expected future oil and natural gas prices decline during 2012, 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 March 26, 2012, the NYMEX-WTI oil spot price was $107.03 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.13 per MMBtu.

Asset Retirement Obligations

The initial estimated asset retirement obligation associated with oil and natural gas properties is recognized as a liability, with a corresponding increase in the carrying value of oil and natural gas properties. Amortization expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the 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, 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. For those derivative contracts that are designated and qualify as hedging instruments, we designate the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. For derivative contracts not designated as hedging instruments, the gain or loss is recognized in current earnings during the period of change. None of our derivatives was designated as a hedging instrument during 2011, 2010 or 2009.

Recently Issued Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities. The amendments in this update require enhanced disclosures around financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. We do not expect this guidance to have any impact on our consolidated financial position, results of operations or cash flows.

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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, 2011, 2010 and 2009. 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.

Supplemental Disclosures Regarding LRR Energy, L.P. Prior to IPO

As noted above, the results of our predecessor discussed above include combined results for both the properties conveyed to us in connection with our IPO and properties retained by our predecessor subsequent to our IPO. The following table provides selected results for only the properties conveyed to us in connection with our IPO. The following information is for informational purposes only and should not be considered indicative of future results.

	Period from January 1 to November 15, 2011	Year Ended December 31, 2010
Production:		
Oil (MBbls)	400	424
Natural gas (MMcf)	7,692	10,118
NGLs (MBbls)	198	279
Total (MBoe)	1,880	2,389
Average net production (Boe/d)	5,893	6,546
Revenues (in thousands):		
Oil	$ 35,729	$ 31,850
Natural gas	31,809	42,722
NGLs	10,899	10,935
Lease operating expenses (in thousands)	$ 16,127	$ 19,080
Production and ad valorem taxes (in thousands)	$ 5,348	$ 7,755

With the exception of natural gas, our production from the Partnership Properties was consistent with 2010 after adjusting 2011 for a full year. Natural gas production declined from 2010 primarily due to the Pecos Slope curtailment discussed above.

Despite lower production, revenues increased in 2011 when adjusted for a full year primarily due to higher oil prices in 2011. Our 2011 lease operating expense was consistent with 2010 when adjusted for a full year. Our 2011 production and ad valorem taxes were slightly lower than 2010 primarily due to changes in the estimates of the appraisals on which our property taxes are calculated.

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.

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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 over 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.

Swaps. 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.

Collars. 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, 2011:

	Index		2012		2013		2014		2015
Natural gas positions									
Price swaps (MMBtus)	NYMEX-HH		3,684,189		5,757,645		5,107,055		4,596,205
Weighted average price		$	6.21	$	5.59	$	5.76	$	5.96
Collars (MMBtus)	NYMEX-HH		2,902,801						
Floor-Ceiling price		$	4.75-7.31	$		$		$	
Oil Positions									

Price swaps (Bbls)	NYMEX-WTI		251,005		289,323		248,149		219,657
Weighted average price		$	102.20	$	101.30	$	100.01	$	98.90
NGL Positions									
Price swaps (Bbls)	Mont Belvieu		164,220						
Weighted average price		$	49.92	$		$		$	

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As of December 31, 2011, the fair market value of our commodity derivative positions was a net asset of $42.9 million.

Interest Rate Risk

At December 31, 2011, we had $155.8 million of debt outstanding under our credit facility, with an effective interest rate of 2.86%. Assuming no change in the amount outstanding, the impact on interest expense of a 10% increase or decrease in the average interest rate, would be approximately $0.4 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 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/Combined 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 Securities Exchange Act, as amended (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 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 management, with the participation of our principal executive officers and principal financial officer, has concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2011.

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Management s Annual Report on Internal Control of Financial Reporting

This Annual Report on Form 10-K does not include a report of management s assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by rules of the SEC for newly public companies. A report of management s assessment and the auditor s attestation report regarding internal control over financial reporting is not required until we file our annual report for the year ended December 31, 2012.

Remediation Steps to Address the 2010 Material Weaknesses

Prior to the completion of our IPO in November 2011, our predecessor was a private entity with limited accounting personnel and other supervisory resources to adequately execute its accounting processes and address its internal control over financial reporting. Our predecessor did not maintain effective controls over the completeness and accuracy of key spreadsheets used in its computations of various estimates, including depletion and asset retirement obligations. Effective controls were not adequately designed or consistently operated to ensure that key computations were capturing the appropriate information completely and accurately before closing adjustments were made to our predecessor s accounting records. The lack of adequate staffing levels and lack of effective controls over the completeness and accuracy of key spreadsheets resulted in insufficient time spent on review and approval of certain information used to prepare our predecessor s financial statements, resulting in several audit adjustments to our predecessor s financial statements for the year ended December 31, 2010. In connection with the audit of our predecessor s financial statements for the year ended December 31, 2010, our predecessor s independent registered accounting firm identified and communicated material weaknesses related to maintaining an effective control environment in that the design and execution of controls have not consistently resulted in effective review and supervision by individuals with financial reporting oversight roles given the lack of adequate staffing levels. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the Partnership s annual or interim financial statements will not be prevented or detected on a timely basis.

During the year ended December 31, 2011, our predecessor hired additional personnel and revised and enhanced the procedures surrounding accounting records and internal controls over financial reporting. These specific enhancements included the following:

- Our predecessor hired full-time employees to replace previously outsourced accounting personnel and also hired personnel in oversight roles to provide effective review and supervision of the staff in our accounting, general ledger and financial reporting departments. In April 2011, our predecessor hired an Operational Controller and General Ledger Manager, and in May 2011, our predecessor hired an SEC Financial Reporting Manager. These personnel aid in the preparation and provide additional review of our operational accounting data, general ledger and financial reporting disclosures.

- Our predecessor implemented additional analysis and reconciliation procedures as it relates to our depletion and depreciation expense calculations, asset retirement obligation calculations and other key spreadsheets.

- Our predecessor implemented software to aid in the tracking of asset retirement obligations in the fourth quarter of 2011.

We have completed the documentation and testing of the corrective procedures described above and, as of December 31, 2011, management has concluded that the steps taken have remediated the material weaknesses previously disclosed in our IPO Prospectus on file with the SEC.

Changes in Internal Controls over Financial Reporting

As described above under Remediation Steps to Address the 2010 Material Weaknesses, there were changes in our internal control over financial reporting during the quarter and year ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Additionally, in connection with our IPO in November 2011, we adopted certain governance policies in order to strengthen our corporate governance and comply with the requirements of the NYSE. These changes included the appointment of three independent members of the Board of Directors, the establishment of Governance Guidelines,

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the establishment of an Audit Committee and the adoption of an Audit Committee Charter and the adoption of a Code of Business Conduct and Ethics. We believe that these positive changes in our control environment provide reasonable assurance as to the effectiveness of our disclosure controls as discussed above.

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 operations of our business. These functions are performed by the employees of Lime Rock Management and OpCo 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 be 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 allows 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 primary responsibility for enterprise-level risk management, while retaining responsibility for oversight of our executive officers in that regard. Our executive officers will offer an enterprise-level risk assessment to the board of directors at least once every year.

Directors and Executive Officers

The following table sets forth certain information regarding the current directors and executive officers of our general partner. Directors are elected for one-year terms.

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Name	Age	Position with our General Partner
Eric Mullins	49	Co-Chief Executive Officer and Chairman
Charles W. Adcock	58	Co-Chief Executive Officer and Director
Christopher A. Butta	51	Vice President and Chief Engineer
Jaime R. Casas	42	Vice President, Chief Financial Officer and Secretary
C. Timothy Miller	52	Vice President and Chief Operating Officer
John A. Bailey (1)	42	Director
Milton Carroll (2)	61	Director
Jonathan C. Farber	43	Director
Robert T. O Connell (3)	73	Director
Townes G. Pressler, Jr.	48	Director

(1) Member of the conflicts and audit committees.

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

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

Directors are elected for one-year terms 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 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 also serves on the Board of Trustees of the YMCA Retirement Fund. Mr. Mullins has been nominated as a director candidate by Anadarko Petroleum Corporation to be included in Anadarko s 2012 proxy statement for election at its 2012 Annual Meeting of Stockholders, on May 15, 2012. 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

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believe that Mr. Adcock s 36 years of 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 Vice President and Chief Engineer. Christopher A. Butta was appointed Vice President and Chief Engineer of our general partner in May 2011. Mr. Butta also serves as the Vice President of Engineering and Chief Engineer of Lime Rock Resources, which positions he has held since October 2008. 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 nine 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, Chief Financial Officer and Secretary. Jaime R. Casas was appointed Vice President, Chief Financial Officer and Secretary 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 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 University of Pennsylvania, with a Master of Business Administration.

C. Timothy Miller Vice President and Chief Operating Officer. C. Timothy Miller was appointed Vice President and Chief Operating Officer of our general partner in May 2011. Mr. Miller also serves as the Vice President of Operations and Chief Operating Officer of Lime Rock Resources, which positions he has held since October 2008. From May 2005 to October 2008, Mr. Miller served as Vice President of Operations of Lime Rock Resources. From 1984 until April 2005, Mr. Miller worked for El Paso Corporation and for Coastal Oil and Gas Company before it merged with El Paso in 2001. During this time, Mr. Miller served in positions of increasing responsibility, working as a petroleum engineer and rising to the position of Vice President-Upper Gulf Coast Production for Coastal Oil and Gas Corporation in 1999. After Coastal s merger with El Paso, Mr. Miller served as Vice President-Gulf of Mexico Production, Vice President-Texas Gulf Coast Technical Group and finally Vice President, Texas Gulf Coast Division, where he was responsible for all of El Paso Corporation s operations in the Gulf Coast area. From 1982 to 1984, Mr. Miller worked as a petroleum engineer for Petro-Lewis Corporation. Mr. Miller is a graduate of the University of Missouri-Rolla, with a Bachelor of Science degree in Petroleum Engineering, and Oklahoma City University, with a Master of Business Administration.

John A. Bailey Director. John A. Bailey was appointed as a member of the board of directors of our general partner in November 2011. Mr. Bailey has been Portfolio Manager, Global Natural Resources, and a Senior Research Analyst at ING Investment Management since June 2011. Mr. Bailey was a founder and Managing Partner of 1859 Partners LLC, an energy investment partnership, from March 2009 until June 2011. From August 2008 until March 2009, Mr. Bailey was Managing Partner of J. Bailey & Co LLC, an energy industry consulting company. From May 2006 until its merger with Denbury Resources Inc. in March 2010, Mr. Bailey served on the board of directors and audit committee of Encore Acquisition Company, an NYSE-listed oil and gas exploration and production company. From December 2006 until August 2008, Mr. Bailey was a Portfolio Manager, Global Energy, at Carlyle Blue Wave Partners Management, LP, an investment partnership. Mr. Bailey served as a director of CrossPoint Energy, an oil and gas exploration and production company listed on the OTC Bulletin Board, from January 2005 until October 2007. From March 2005 to October 2006, Mr. Bailey was a Vice President, Energy at Amaranth Group LLC, an investment fund, and a consultant to Amaranth Group LLC from October 2004 until

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March 2005. From October 2000 until August 2004, Mr. Bailey was an equity research analyst and Vice President of Equity Research for Deutsche Bank Securities focusing on the exploration and production industry in North America. From May 1997 until October 2000, Mr. Bailey was part of the oil and natural gas equity research group at Donaldson, Lufkin & Jenrette, Inc. and from May 1993 until May 1997, Mr. Bailey was part of the economic fixed income research group at Donaldson, Lufkin & Jenrette, Inc. Mr. Bailey received a Bachelor of Arts degree in Economics and Government from Cornell University. We believe that Mr. Bailey s financial and energy investment experience and board and audit committee service bring valuable industry experience and corporate governance skills to the board of directors.

Milton Carroll Director. Milton Carroll was appointed as a member of the board of directors of our general partner in November 2011. Mr. Carroll is Chairman and founder of Instrument Products, Inc., an oil-tool manufacturing company in Houston, Texas. Mr. Carroll currently serves as Chairman of Houston-based CenterPoint Energy, Inc., where he has been a director since 1992. He has also served as a director of Halliburton Company since 2006, where he is a member of the compensation committee and the nominating and corporate governance committee; Western Gas Holdings, LLC, the general partner of Western Gas Partners, LP, since April 2008, where he is chairman of the special committee; and LyondellBasell Industries N.V. since July 2010, where he is the chairman of the compensation committee and a member of the nominating and governance committee, and formerly a member of the audit committee. Additionally, Mr. Carroll has served as a director of Healthcare Service Corporation, a Chicago-based company operating through its Blue Cross and Blue Shield divisions in Illinois, New Mexico, Oklahoma and Texas, since 1998 and as its chairman since 2002. Mr. Carroll previously served as a director of EGL, Inc. from 2003 to 2007; DCP Midstream GP, LLC, the general partner of DCP Midstream Partners, LP, from 2005 to 2006; Devon Energy Corporation from 2003 to 2005; and Texas Eastern Products Pipeline Company, LLC, the general partner of TEPPCO Partners, L.P., from 1997 to 2005. Mr. Carroll holds a Bachelor of Science degree in Industrial Technology from Texas Southern University. We believe that Mr. Carroll s current and prior board and committee service and his knowledge of the oil and natural gas industry provide the board of directors with significant corporate governance experience and valuable industry knowledge.

Jonathan C. Farber Director.Jonathan C. Farber was appointed as a member of the board of directors of our general partner in May 2011. Mr. Farber also serves as a Managing Director of Lime Rock Partners, a private equity firm he co-founded in 1998 to focus on investments of growth capital in energy companies worldwide, as well as Manager of the general partner of Lime Rock Management and the upper tier general partner of Fund II and Managing Member of the upper tier general partner of Fund I. Mr. Farber began his career in 1990 in the Investment Research Department of Goldman Sachs, rising from a securities analyst to Vice President in the Investment Banking Division, where he was involved in private equity and large merger and acquisition transactions. Mr. Farber currently serves on the board of directors of Arena Exploration, Augustus Energy Partners, Black Shire Energy, CrownRock, Laricina Energy, PDC Mountaineer and Vantage Energy. He previously served on the board of directors of RMP Energy, Coronado Resources, Deer Creek Energy, LMP Exploration Holdings, Torex Resources, Slate River Resources, U.S. Exploration Holdings, and Venture Production. Mr. Farber is a graduate of the School of Foreign Service of Georgetown University, with a Bachelor of Science in Foreign Service degree. We believe that Mr. Farber s extensive financial, investment banking and private equity experience, as well as his experience on the boards of directors of public and numerous private energy companies, bring substantial leadership skill and experience to the board of directors.

Robert T. O Connell Director. Robert T. O Connell was appointed as a member of the board of directors of our general partner in November 2011. Mr. O Connell served as a director of CenterPoint Energy, Inc., an energy delivery company listed on the NYSE, from 2004 until April 2011 when he retired, and also served, at various times during his tenure, as Chairman of the finance committee and on the audit committee of CenterPoint Energy. Mr. O Connell also served as a director of GulfMark Offshore, Inc., an NYSE-listed provider of marine services to offshore exploration and production companies from 2006 to June 2011 when he retired, and also served on the audit committee of GulfMark during his tenure. From 1997 to 2003, Mr. O Connell served as a director of RWD Technologies, Inc., a professional services company, and as its Chief Financial Officer from August 2000 to July 2001, and Senior Vice President of strategic business planning from August 1997 to July 2001. Mr. O Connell served as Senior Vice President and Chief Staff Officer of EMC Corporation, a provider of intelligent enterprise storage and retrieval technology listed on the NYSE, from 1995 to 1997. Between 1965 and 1994, Mr. O Connell held various positions at General Motors Corporation, an NYSE-listed global automotive company, including Chief Financial Officer of General Motors Corporation from 1988 to 1992 and Chairman and Chief Executive Officer of

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General Motors Acceptance Corporation from 1992 to 1994. Beginning in 2003, he served two terms as a Governor-appointed member of the Boston Finance Commission which oversees the City of Boston. Mr. O Connell earned a Bachelor of Arts degree in Economics from Yale University and a Master of Business Administration from Harvard Business School. We believe that Mr. O Connell s financial and executive management expertise, including his experience as the Chief Financial Officer of a major public corporation, and his prior board service bring substantial leadership skill and financial expertise to the board of directors.

Townes G. Pressler, Jr. Director. Townes G. Pressler, Jr. was appointed as a member of the board of directors of our general partner in May 2011. Mr. Pressler also serves as a Managing Director of Lime Rock Partners, a position he has held since joining Lime Rock Partners in 2007. From 2004 to 2007, Mr. Pressler served as Principal of Peregrine Oil & Gas LP, a private equity-backed independent oil and natural gas producer he co-founded focused on the Gulf of Mexico. From 2002 to 2004, Mr. Pressler worked for Harrison Lovegrove & Co. as a Managing Director. From 1996 to 2002, Mr. Pressler served in various capacities at Donaldson, Lufkin & Jenrette, later becoming Managing Director of the Global Energy Group of Credit Suisse after Credit Suisse s acquisition of DLJ. Prior to that time, Mr. Pressler worked for five years as an energy investment banker and three years as an energy commercial lender. Mr. Pressler currently serves on the board of directors of Black Shire Energy, Braden Exploration, Capstone Natural Resources Holdings, LLC, Chinook Energy Inc., Lafayette Workboat Holdings and TAW Energy Services. He previously served on the board of directors of PDC Mountaineer. Mr. Pressler is a graduate of Washington & Lee University, with a Bachelor of Arts degree, and The University of Texas at Austin, with a Master of Business Administration. We believe that Mr. Pressler s considerable financial and energy investment banking experience, as well as his experience on the boards of directors of numerous private energy companies, bring important and valuable skills to the board of directors.

Non-Management Executive Sessions and Unitholder Communication

NYSE listing standards require regular executive sessions of the non-management directors of a listed company, and an executive session for independent directors at least once a year. On a regular basis, all of our non-management directors will meet in an executive session. At least annually, our independent directors will meet in executive session without management participation or participation by non-independent directors.

Interested parties can communicate directly with non-management directors by mail in care of LRR Energy, L.P., Heritage Plaza, 1111 Bagby Street, Suite 4600, Houston, Texas 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Committees of the Board of Directors and Independence Determination

Our board of directors has established an audit committee and a conflicts committee. The NYSE does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating and corporate governance committee. We are, however, required to have an audit committee of at least three members, all of which are required to meet the independence and experience standards established by the NYSE and SEC rules. Our general partner s board of directors has affirmatively determined Messrs. Bailey, Carroll and O Connell satisfy the NYSE and SEC requirements for independence.

Audit Committee

The audit committee consists of Messrs. O Connell (Chairman), Bailey and Carroll, all of whom meet the independence and expertise standards established by the NYSE and the Exchange Act. Our general partner s board of directors has determined that Mr. O Connell is an audit committee financial expert as defined under SEC rules. The audit committee held one meeting in 2011.

The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public

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accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has unrestricted access to the audit committee and our management, as necessary.

A copy of the audit committee charter is available on our website at www.lrrenergy.com. We will provide a copy of our audit committee charter to any person, without charge, upon request to LRE GP, LLC, Heritage Plaza, 1111 Bagby Street, Suite 4600, Houston, Texas 77002, Attn: Corporate Secretary.

Conflicts Committee

The conflicts committee consists of Messrs. Carroll (Chairman), Bailey and O Connell, all of whom meet the independence standards established by the NYSE. The conflicts committee reviews specific matters that the board of directors believes may involve conflicts of interest (including certain transactions with affiliates of our general partner, including Lime Rock Resources and Lime Rock Partners) and that the board determines to submit to the conflicts committee for review. Our general partner may, but is not required to, seek approval from the conflicts committee of a resolution of a conflict of interest with our general partner or affiliates. The conflicts committee will determine if the resolution of the conflict of interest is fair and reasonable to us. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. The conflicts committee held no meetings in 2011.

Meetings and Other Information

The board of directors held one meeting in 2011.

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

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires executive officers and directors of LRE GP, LLC and persons who beneficially own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act to file certain reports with the SEC and NYSE concerning their beneficial ownership of such securities.

Based solely on a review of the copies of reports on Forms 3,4 and 5 and amendments thereto furnished to us and written representations from the executive officers and directors of LRE GP, LLC, we believe that during the year ended December 31, 2011 the officers and directors of LRE GP, LLC and beneficial owners of more than 10% of our equity securities registered pursuant to Section 12 were in compliance with the applicable requirements of Section 16(a).

Corporate Governance

The corporate governance of LRE GP, LLC is, in effect the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement.

The board of directors of LRE GP, LLC has adopted a code of business conduct and ethics that applies to all officers, directors and employees of LRE GP, LLC and its affiliates, including the Chief Executive Officers, Chief Financial Officer and Chief Accounting Officer of our general partner. In addition, the board has adopted governance guidelines for the board and its directors. Copies of the code of business conduct and ethics and the governance guidelines are available on our website at www.lrrenergy.com. We will provide copies of our code of business conduct and ethics and the governance guidelines to any person, without charge, upon request to LRE GP, LLC, Heritage Plaza, 1111 Bagby Street, Suite 4600, Houston, Texas 77002, Attn: Corporate Secretary.

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Reimbursement of Expenses of our General Partner

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates, including Lime Rock Management and OpCo, may be reimbursed.

In connection with our IPO, we entered into a services agreement with Lime Rock Management and OpCo pursuant to which management, administrative and operational services are provided to our general partner and us to manage and operate our business. Our general partner reimburses each of Lime Rock Management and OpCo, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement, and we reimburse our general partner for such payments it makes to Lime Rock Management and OpCo. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated to our general partner. Lime Rock Management and OpCo has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate to us. In turn, our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.

ITEM 11. EXECUTIVE COMPENSATION.

Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate the executive officers of our general partner. Rather, under the services agreement, our general partner reimburses Lime Rock Management for the allocable expenses Lime Rock Management incurs in compensating our general partner s executive officers, and we reimburse our general partner for such payments it makes to Lime Rock Management. As described in the Compensation Discussion and Analysis, or CD&A, below, decisions regarding the non-equity based compensation of our general partner s Co-Chief Executive Officers are made by Lime Rock Management and decisions regarding the non-equity based compensation of our other executive officers are made by Lime Rock Management after consulting with and considering recommendations by our Co-Chief Executive Officers. Equity-based compensation pursuant to our long-term incentive plan is determined and approved by the board of directors of our general partner.

The board of directors of our general partner has reviewed and discussed with management the CD&A set forth below. Based on this review and discussion, the board of directors determined that the CD&A be included in this Annual Report on Form 10-K for the year ended December 31, 2011.

Submitted by: Eric Mullins
Charles W. Adcock
John A. Bailey
Milton Carroll
Jonathan C. Farber
Robert T. O Connell

Townes G. Pressler, Jr.

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

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Compensation Discussion and Analysis

Overview

Our operations and activities are managed by our general partner. However, neither we nor our general partner directly employ any of the persons responsible for managing our business. Rather, all of our general partner s executive officers are employed by Lime Rock Management. As a result, the compensation of our general partner s executive officers (other than equity-based incentive grants, which are determined by the board of directors of our general partner) is determined and paid by Lime Rock Management. Under the services agreement, our general partner reimburses Lime Rock Management, on a monthly basis, for the allocable expenses it incurs in compensating our general partner s executive officers, and we reimburse our general partner for such payments it makes to Lime Rock Management. Please read Item 13. Certain Relationships and Related Party Transactions Services Agreement for more information on the services agreement. Although we bear an allocated portion of Lime Rock Management s costs of providing compensation and benefits to the Lime Rock Management employees who serve as the executive officers of our general partner, we have no control over such costs and do not establish or direct the compensation policies or practices of Lime Rock Management. Each of our executive officers, other than our Chief Financial Officer who is devoted full-time to our business, performs services for Lime Rock Management and its affiliates, including Lime Rock Resources.

We and our general partner were formed in April 2011 and, therefore, we incurred no cost or liability with respect to compensation of our general partner s executive officers, nor did our general partner accrue any liabilities for compensation for its executive officers, for fiscal years prior to 2011. Our initial public offering was completed on November 16, 2011.

This CD&A provides general information about the compensation paid to the executive officers of our general partner identified in the following table, who we refer to in this CD&A and the tables that follow as our named executive officers.

Name	**Principal Position**
Eric Mullins	Co-Chief Executive Officer
Charles W. Adcock	Co-Chief Executive Officer
Jaime R. Casas	Vice President, Chief Financial Officer and Secretary(1)
Morrow B. Evans	Vice President, Chief Financial Officer and Secretary(2)

(1) Mr. Casas was appointed as the Vice President, Chief Financial Officer and Secretary of our general partner in July 2011.

(2) Mr. Evans served as the Vice President, Chief Financial Officer and Secretary of our general partner from May 2011 to July 2011. Mr. Evans agreed to serve in such capacity until Lime Rock Management hired a Chief Financial Officer that would be devoted full time to our business.

Our three most highly compensated executive officers other than Messrs. Mullins, Adcock, Casas and Evans who were serving as executive officers of our general partner as of December 31, 2011 received total compensation of less than $100,000 for the fiscal year ended December 31, 2011. Accordingly, we have not provided information about the compensation paid to these executive officers in this CD&A.

The executive officers of our general partner, other than Mr. Casas who is devoted full time to our business, allocate their time between managing our business and affairs and the business and affairs of Lime Rock Resources and its affiliates. Under the services agreement, the compensation costs of our named executive officers, including Mr. Casas, are allocated to us on a monthly basis based on the estimated amount of time that each officer spends on our business.

Lime Rock Management, as the employer of our executive officers, has responsibility and authority for non-equity based compensation related decisions for our Co-Chief Executive Officers and, upon consultation and recommendations by our Co-Chief Executive Officers, for the other executive officers of our general partner. Equity grants pursuant to our long-term incentive plan are determined and approved by the board of directors of our general partner. Historically, all compensation decisions for employees of Lime Rock Management, including those for the

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individuals who are executive officers of our general partner, have been made at the discretion of Mr. Jonathan Farber and Mr. John Reynolds, who control Lime Rock Management. Mr. Farber serves as a director of our general partner. Lime Rock Management has historically compensated its executive officers with base salary and cash bonuses. Historically, Messrs. Farber and Reynolds have determined the overall compensation philosophy and set the final compensation of the executive officers of Lime Rock Management without the assistance of a compensation consultant. None of our executive officers have employment agreements with us, Lime Rock Management or any of its affiliates.

Objectives of Our Compensation Program

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

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

What Our Compensation Program is Designed to Reward

Our compensation program is designed to reward performance that contributes to the achievement of our business strategy on both a short-term and a long-term basis. The primary long-term measure of our performance is our ability to sustain or increase our quarterly distributions to our unitholders. In addition, we reward qualities that we believe help achieve our strategy such as teamwork; individual performance in light of general economic and industry specific conditions; performance that supports our core values; resourcefulness; the ability to manage our existing assets; the ability to explore new avenues to increase oil and natural gas production and reserves; level of job responsibility; and tenure.

Benchmarking

As discussed above, one of the objectives of our compensation program is to provide our executive officers total compensation competitive with that of other executive officers employed by exploration and production companies and publicly traded partnerships of similar size. Accordingly, our Co-Chief Executive Officers reviewed our peer group s 10-K and proxies to determine the compensation paid our peer group. This peer group was comprised of the following exploration and production companies and publicly traded partnerships: Atlas Energy, L.P., Breitburn Energy Partners, L.P., Eagle Rock Energy Partners, L.P., Encore Energy Partners LP, EV Energy Partners, L.P., Legacy Reserves LP, Linn Energy, LLC, Pioneer Southwest Energy Partners L.P., QR Energy, LP and Vanguard Natural Resources, LLC. Our Co-Chief Executive Officers used this analysis to make recommendations to Lime Rock Management regarding the compensation to be paid by Lime Rock Management to Mr. Casas. However, our Co-Chief Executive Officers and Lime Rock Management did not specifically benchmark the base salary, cash bonus or long-term equity-based compensation to any formulaic percentage of, or numerical average of, the compensation levels at these other companies.

Performance Metrics

Neither Lime Rock Management nor our board of directors relies on specific performance metrics or objective targets when determining compensation. Instead, Lime Rock Management and our board of directors make subjective determinations as to the appropriate compensation for each named executive officer based on their view of the individual s performance and our performance during the prior fiscal year without any weight or formula given to any specific performance measures. In addition, their determinations give consideration to the level and position of each named executive officer and relative compensation paid to other executive officers.

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Elements of Our Compensation Program and Why We Pay Each Element

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

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

Base Salary

We pay a base salary in order to recognize each executive officer s unique value and contributions to our success in light of salary norms in the industry; to provide executives with sufficient, regularly paid income; and to reflect position and level of responsibility.

In 2011, Lime Rock Management, after consultation with and recommendations by our Co-Chief Executive Officers, determined that Mr. Casas should receive an annual salary of $225,000. Lime Rock Management based its decision on Mr. Casas position and level of responsibility, Mr. Casas expected contribution to us and general salary norms in the industry. The salary shown for Mr. Casas in the Summary Compensation Table below reflects this annual salary of $225,000 prorated for the period from November 16 to December 31, 2011.

Discretionary Cash Bonus

A significant portion of the compensation of our named executive officers consists of a discretionary annual cash bonus. While base salaries offer an important retention element by providing a guaranteed income stream to our employees, we hope to incentivize and motivate our employees to strive for both individual and overall company success by providing a substantial portion of compensation only when performance for the year calls for an additional compensatory award. We expect that future annual cash bonuses to our executive officers with respect to services provided to us will be determined based on subjective evaluation of personal performance and our financial performance as measured across a fiscal year. Such bonuses and other incentive compensation are not tied to any specific performance measure of Lime Rock Management, Lime Rock Resources or Lime Rock Partners or any other affiliate of ours. We feel our industry has historically relied heavily on performance-based cash bonuses to compensate executive officers, and we want to compensate our executives in line with industry practices.

Mr. Casas is eligible to receive a cash bonus at the target level of 100% of his base salary based on his performance. In 2011, Mr. Casas received a cash bonus of $225,000 reflecting Lime Rock Management s determination, based on recommendations of our Co-Chief Executive Officers.

Long-Term Equity-Based Compensation

Prior to our initial public offering, the board of directors adopted the LRE GP, LLC Long-Term Incentive Plan, or LTIP, for employees, officers, consultants and directors of our general partner and its affiliates, including Lime Rock Management, who perform services for us. All Lime Rock Management employees, including each of our named executive officers, are eligible to participate in the LTIP. The purpose of awards under the LTIP is to provide additional incentive compensation, at the discretion of the board, to employees providing services to us, and to align the economic interests of such employees with the interests of our unitholders. The LTIP provides for the grant of restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. As of December 31, 2011, there were 1,457,626 common units that remain available for issuance under the LTIP.

We have no set formula for granting awards to our named executive officers. In determining whether to grant awards and the amount of any awards, the board of directors of our general partner takes into consideration

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subjective and discretionary factors such as the individual s current and expected future performance, level of responsibility, retention considerations, industry trends and the total compensation package.

Upon the closing of our initial public offering, the board of directors of our general partner granted Mr. Casas 39,474 restricted units under the LTIP with a grant date fair value of $750,006. These restricted units vest in equal one-third increments over a 36-month period (i.e., approximately 33.3% vest at each one-year anniversary of the date of grant), so that the restricted units granted at the closing of our initial public offering will be 100% vested on November 16, 2014 and provided that he has continuously provided services to us, our general partner or any of our respective affiliates, without interruption, from the date of grant through each applicable vesting date. In approving the grant of restricted units to Mr. Casas, the board took into account Mr. Casas expected future performance, his level of responsibility and the board s desire to retain Mr. Casas over the long-term.

On March 20, 2012, the board of directors of our general partner granted Mr. Casas 8,400 restricted units under the LTIP. These restricted units vest in equal one-third increments over a 36-month period (i.e., approximately 33.3% vest at each one-year anniversary of the date of grant), so that the restricted units granted will be 100% vested on March 20, 2015 and provided that he has continuously provided services to us, our general partner or any of our respective affiliates, without interruption, from the date of grant through each applicable vesting date.

The restricted units granted to Mr. Casas will become fully vested upon a change of control or termination of employment due to death or disability. Mr. Casas restricted unit award includes unit distribution rights (UDRs), which enable him to receive cash distributions on our restricted units to the same extent as our unitholders receive cash distributions on our common units. Such distributions are paid to Mr. Casas at the same time as cash distributions are paid to our common unitholders.

With respect to future LTIP awards, we intend to continue to primarily utilize restricted unit awards with UDRs. These awards are intended to align the interests of key employees (including our named executive officers) with those of our unitholders.

Benefits

Lime Rock Management does not maintain a defined benefit or pension plan for our named executive officers because it believes such plans primarily reward longevity rather than performance. Through Insperity PEO Services, L.P., Lime Rock Management and OpCo, Inc. provide a basic benefits package to all of their employees that includes health, dental, basic term life insurance, personal accident insurance and short and long-term disability coverage. Employees provided to us under the services agreement, including our named executive officers, are entitled to the same basic benefits. For the period between November 16, 2011 and December 31, 2011, Lime Rock Management provided a dollar-for-dollar matching contribution under the 401(k) plan on the first 5% of eligible compensation contributed to the plan, up to $10,000.

How Elements of Our Compensation Program are Related to Each Other

We view the various components of compensation as related but distinct and emphasize pay for performance with a significant portion of total compensation reflecting a risk aspect tied to long-term and short-term strategic goals. Our compensation philosophy is to foster entrepreneurship at all levels of our organization by making long-term equity-based incentives, particularly restricted unit grants, a significant component of executive compensation. We determine the appropriate level for each compensation component based on our overall goal to attract, motivate and retain key employees. The board of directors of our general partner, however, has not adopted any formal or informal policies or guidelines for allocating compensation between long-term and currently paid-out compensation, between cash and non-cash compensation, or among different forms of non-cash compensation. All compensation decisions are discretionary and subject to the ultimate decision making authority of Lime Rock Management, except for equity awards under the LTIP, which are determined by the board of directors of our general partner.

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Tax Deductibility of Compensation

With respect to the deduction limitations imposed under Section 162(m) of the Internal Revenue Code, we are a limited partnership and do not meet the definition of a corporation under Section 162(m). Accordingly, such limitations do not apply to compensation paid to our named executive officers.

Summary Compensation Table

The following table sets forth the components of and total compensation paid, accrued or otherwise expensed by us with respect to the compensation of our named executive officers for the fiscal year ended December 31, 2011.

Name	Year		Salary(1)		Bonus(2)		Stock Awards(3) (4)		All Other Compensation(5)		Total Compensation
Eric Mullins *Co-Chief Executive Officer*	2011	$	29,712	$		$		$	1,879	$	31,591
Charles W. Adcock *Co-Chief Executive Officer*	2011	$	21,775	$		$		$	1,305	$	23,080
Jaime R. Casas *Vice President, Chief Financial Officer and Secretary*	2011	$	28,125	$	225,000	$	750,006	$	14,358	$	1,017,489
Morrow B. Evans* *Vice President, Chief Financial Officer and Secretary*	2011	$	5,104	$	6,927	$		$	568	$	12,599

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(1) Reflects the portion of the base salaries paid by Lime Rock Management to each of our named executive officers (other than Mr. Casas) that are reimbursable by our general partner under the services agreement for the period beginning on November 16, 2011, the date of the closing of our initial public offering, and ending on December 31, 2011. The salary shown for Mr. Casas reflects his annual salary of $225,000 prorated for the period from November 16 to December 31, 2011. Because Mr. Casas is devoted full-time to our business, our general partner reimburses Lime Rock Management for the full amount of Mr. Casas annual salary, and we reimburse our general partner for such amount. Our general partner did not reimburse Lime Rock Management for any portion of the base salary Lime Rock Management paid to Mr. Evans prior to the date of our IPO (November 16, 2011).

(2) Reflects the portion of the cash bonuses paid by Lime Rock Management to each of our named executive officers (other than Mr. Casas) that are reimbursable by our general partner under the services agreement for the period beginning on November 16, 2011, the date of the closing of our initial public offering, and ending on December 31, 2011. For Mr. Casas, reflects the cash bonus paid by Lime Rock Management to Mr. Casas that is reimbursable by our general partner under the services agreement. Because Mr. Casas is devoted full-time to our business, our general partner reimburses Lime Rock Management for the full amount of the cash bonus paid by Lime Rock Management to Mr. Casas, and we reimburse our general partner for such amount.

(3) Reflects the aggregate grant date fair value of the restricted unit award granted under the LTIP computed in accordance with FASB ASC Topic 718. See Note 12 to our consolidated/combined financial statements for fiscal 2011 for additional detail regarding assumptions underlying the value of this equity award.

(4) Mr. Casas received 39,474 restricted units under the LTIP upon the closing of our initial public offering. These restricted units vest in equal one-third increments over a 36-month period, provided that Mr. Casas has continuously provided services to us, our general partner or any of our respective affiliates, without interruption, from the date of grant through each applicable vesting date.

(5) Insperity PEO provides us with full human resources services in exchange for a fee. Our benefits and these fees are charged back to us through Lime Rock Management. These costs reflect the benefits, fees and taxes paid by our general partner under the services agreement for the period beginning on November 16, 2011, the date of the closing of our initial public offering, and ending on December 31, 2011. Additionally,

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Mr. Casas amount reflects our matching 401(k) contribution to him for the period from November 16 to December 31, 2011.

*Mr. Evans served as an executive officer prior to our initial public offering, from May 2011 to July 2011.

Grants of Plan-Based Awards for Fiscal 2011

The following table sets forth certain information with respect to grants of restricted units to our named executive officers in fiscal 2011.

Name	Grant Date (1)	Approval Date (1)	All Other Unit Awards: Number of Shares of Unit or Units (2)		Grant Date Fair Value of Unit and Option Awards (3)
Eric Mullins				$	
Charles W. Adcock				$	
Jaime R. Casas	11/16/2011	11/8/2011	39,474	$	750,006
Morrow B. Evans				$	

(1) The board of directors of our general partner approved the grant of restricted units to Mr. Casas on November 8, 2011 in connection with our initial public offering. The board s approval provided for the restricted unit grant date to be the closing date of our initial public offering (November 16, 2011).

(2) Reflects the grant of restricted units under the LTIP made to Mr. Casas in connection with our initial public offering. The restricted units vest over three years in equal amounts (subject to rounding) on the anniversary of the grant date of the award, subject to continued service. The restricted units are entitled to receive quarterly distributions during the vesting period.

(3) Reflects the aggregate grant date fair value of the restricted unit award granted under the LTIP computed in accordance with FASB ASC Topic 718.

Outstanding Equity Awards at December 31, 2011

The following table reflects outstanding equity awards as of December 31, 2011 for each of our named executive officers.

Name	Number of Units That Have Not Vested(1)		Market Value of Units That Have Not Vested (2)
Eric Mullins		$	
Charles W. Adcock		$	

Jaime R. Casas	39,474	$	774,085
Morrow B. Evans		$	

(1) 13,158 of the restricted units will vest on November 16, 2012, 13,158 of the restricted units will vest on November 16, 2013, and 13,158 of the restricted units will vest on November 16, 2014, subject to continued service.

(2) Amount derived by multiplying the total number of restricted common units outstanding for Mr. Casas by the closing price of our common units on December 30, 2011, which was $19.61 per common unit.

Option Exercises and Units Vested

No equity-based awards held by our named executive officers vested or were exercised during fiscal 2011.

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Pension Benefits

Currently we do not, and we do not intend to, provide pension benefits to our named executive officers. Our general partner may change this policy in the future.

Nonqualified Deferred Compensation

Currently we do not, and we do not intend to, sponsor or adopt a defined benefit pension plan or nonqualified deferred compensation plan. Our general partner may change this policy in the future.

Potential Payments Upon Termination or Change in Control

Our named executive officers do not have any employment agreements that call for payment of termination or severance benefits or that provide for any payments in the event of a change in control of us or our general partner. However, under the LTIP and the award agreement used to make grants of restricted units to our named executive officers, if a named executive officer ceases to provide services to us, our general partner and our respective affiliates by reason of the officer s death or disability or upon the occurrence of change of control (as defined below) while the named executive officer is providing services to us, our general partner or any of our respective affiliates, any unvested portion of the restricted units granted to the named executive officer will immediately become fully vested. For this purpose, a change of control will be deemed to have occurred (i) if any person or group, other than members of our general partner, us or an affiliate of either our general partner or us, becomes the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the voting power of the voting securities of either our general partner or us; (ii) if the members of our general partner or our limited partners approve, in one or a series of transactions, a plan of complete liquidation of our general partner or us; (iii) upon the sale or other disposition by either our general partner or us of all or substantially all of its or our assets in one or more transactions to any person (other than our general partner, us or any of the respective affiliates); or (iv) if our general partner or an affiliate of our general partner or us ceases to be the general partner of us.

The following table quantifies our best estimates as to the amounts that each of our named executive officers would be entitled to receive upon a termination of employment as a result of his death or disability or upon a change of control, as applicable, assuming that such event occurred on December 30, 2011 and using our closing stock price on that date of $19.61. The precise amount that each of our named executive officers would receive cannot be determined with any certainty until an actual termination or change of control has occurred. Therefore, such amounts should be considered forward-looking statements.

Name		**Termination of Employment by Reason of Death or Disability (1)**		**Occurrence of a Change of Control (1)**
Eric Mullins	$		$	
Charles W. Adcock	$		$	
Jaime R. Casas	$	774,085	$	774,085
Morrow B. Evans	$		$	

(1) The value of the accelerated vesting of the restricted units granted to Mr. Casas is based upon the closing price of our common units on December 30, 2011, $19.61, multiplied by the number of restricted units that would vest upon the occurrence of the event indicated.

Compensation of Directors

Officers and employees of our general partner and its affiliates, including Lime Rock Management, who also serve as directors do not receive additional compensation for their service as a director of our general partner. The following table sets forth a summary of the compensation earned by each of the non-employee directors of our general partner in 2011.

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Name		Fees Earned or Paid in Cash(1)		Unit Awards(2)		Total
John A. Bailey	$	8,750	$	17,280	$	26,030
Milton Carroll	$	8,750	$	17,280	$	26,030
Robert T. O Connell	$	8,750	$	17,280	$	26,030

(1) Includes annual retainer fee and board meeting fees. Messrs. Bailey, Carroll and O Connell were appointed to the board of directors of our general partner in November 2011 in connection with our initial public offering. Fees earned or paid reflect a partial year of service, prorated for the period beginning November 16, 2011 and ending on December 31, 2011.

(2) Reflects the aggregate grant date fair value of the restricted unit awards granted to the non-employee directors under the LTIP computed in accordance with FASB ASC Topic 718. See Note 12 to our consolidated/combined financial statements for fiscal 2011 for additional detail regarding assumptions underlying the value of these equity awards.

For the year ended December 31, 2011, the non-employee directors of our general partner listed in the preceding table were compensated as follows:

- Each non-employee director received a $6,250 cash retainer representing a $50,000 annual cash retainer prorated for the portion of 2011 following the closing of our initial public offering.

- Each non-employee director received a meeting fee of $2,500 for each day that there was a board meeting and the director attended the meeting in person.

- Each non-employee director received a grant of 1,000 restricted units. The restricted units vest over three years in equal amounts (subject to rounding) on the anniversary of the grant date of the award, subject to continued service. The restricted units are entitled to receive quarterly distributions during the vesting period.

For 2012, the cash compensation of our non-employee directors of our general partner will be as follows: (i) a $50,000 annual retainer; (ii) meeting fees of $2,500 for each day that there is a board meeting and the director attends the meeting in person; and (iii) meeting fees of $1,500 for each day that there is a telephonic board meeting at which a vote is taken and in which the director participates.

In addition, each non-employee director will be reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees. Each director is fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law.

Compensation Practices as They Relate to Risk Management

We do not believe that there is a reasonable likelihood that our compensation policy could have a material adverse effect on us. Short-term annual incentives are generally paid pursuant to discretionary bonuses, which enables Lime Rock Management to assess the actual behavior of its employees as it relates to risk taking in awarding bonus amounts. Further, our use of equity-based long-term incentive compensation serves our compensation program s goal of aligning the interests of executives and unitholders, thereby reducing the incentives to unnecessary risk taking. In addition, from a general risk management perspective, our policy is to conduct our commercial activities in a manner intended to control and minimize the potential for unwarranted risk-taking.

Compensation Committee Interlocks and Insider Participation

None of the directors or executive officers of our general partner served as members of the compensation committee or board of directors of another entity that has or had an executive officer who served as a member of the board of directors of our general partner during 2011. As previously noted, we do not have a separate compensation committee. As described in the CD&A above, decisions regarding the compensation of our general partner s Co-Chief Executive Officers are made by Lime Rock Management and decisions regarding the compensation of our other named executive officers are made by Lime Rock Management, after Lime Rock Management consults and

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considers recommendations by our Co-Chief Executive Officers, both of whom are members of the board of directors of our general partner.

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

The following table sets forth the beneficial ownership of our common and subordinated units as of March 16, 2012 for:

- each person known by us to be a beneficial owner of 5% or more of our common and subordinated units;
- each of the directors of our general partner;
- each named executive officer of our general partner; and
- all directors and executive officers of our general partner as a group.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days of March 16, 2012. Under these rules, more than one person may be deemed a beneficial owner of the same securities, and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Except as indicated by footnote, to our knowledge the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

The percentage of common units beneficially owned is based on 15,700,074 common units outstanding as of March 16, 2012, the percentage of subordinated units beneficially owned is based on 6,720,000 subordinated units outstanding as of March 16, 2012 and the percentage of total common and subordinated units beneficially owned is based on 22,420,074 common and subordinated units outstanding as of March 16, 2012.

Name of Beneficial Owner(1)	Common Units Beneficially Owned(2)	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Common and Subordinated Units Beneficially Owned
Fund I(3)	5,049,600	32.2%	6,720,000	100.0%	52.5%
Jonathan C. Farber(3) (4)	5,056,600	32.2%	6,720,000	100.0%	52.5%
John A. Bailey(5)	1,000	*			*
Milton Carroll(5)	2,000	*			*

Robert T. O Connell(5)	11,000	*			*
Townes G. Pressler, Jr.	3,000	*			*
Charles W. Adcock(6)	16,000	*			*
Eric Mullins	15,000	*			*
Jaime R. Casas(7)	39,474	*			*
C. Timothy Miller	3,000	*			*
Christopher A. Butta	300	*			*
All executive officers, and directors as a group (ten persons)	5,147,374	32.8%	6,720,000	100.0%	52.9%

* Percentage of units beneficially owned does not exceed 1%.

(1) The address for all beneficial owners in this table is Heritage Plaza, 1111 Bagby Street, Suite 4600, Houston, Texas 77002. There are no options, warrants or other rights or obligations outstanding that are currently exercisable or exercisable within 60 days into common or subordinated units.

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(2) Includes common units that were awarded as LTIP units and common units that were purchased in the directed unit program at the closing of the IPO and in the open market.

(3) Fund I consists 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), which are controlled indirectly by Jonathan C. Farber, one of our general partner s directors, and John T. Reynolds. Messrs. Farber and Reynolds are Managing Members of LRR GP, LLC (LRR), which is the general partner of Lime Rock Resources GP, L.P. (Lime Rock GP), which is the sole member of each of Lime Rock Resources A GP, LLC (Lime Rock A GP) and Lime Rock Resources C GP, LLC (Lime Rock C GP). Lime Rock A GP is the general partner of LRR A, Lime Rock GP is the general partner of LRR B and Lime Rock C GP is the general partner of LRR C.

Each of Messrs. Farber and Reynolds, LRR, Lime Rock GP, Lime Rock A GP and Lime Rock C GP may be deemed to share voting and dispositive power over the securities held by Fund I; thus, each may also be deemed to be the beneficial owner of the securities held by Fund I. Each of Messrs. Farber and Reynolds, LRR, Lime Rock GP, Lime Rock A GP and Lime Rock C GP disclaims beneficial ownership of the reported securities held by Fund I in excess of such entity s or person s respective pecuniary interest in the securities. LRR A, LRR B and LRR C hold the following limited partner interests in us:

- LRR A owns 721,558 common units and 960,247 subordinated units;
- LRR B owns 239,230 common units and 318,368 subordinated units; and
- LRR C owns 4,088,812 common units and 5,441,385 subordinated units.

(4) Includes 7,000 common units held by Mr. Farber directly.

(5) Includes 1,000 restricted units granted to our general partner s non-employee directors.

(6) Includes 1,000 units held by Mr. Adcock s son. Mr. Adcock disclaims beneficial ownership of these securities.

(7) Includes 39,474 restricted units granted to Mr. Casas pursuant to our long-term incentive plan.

LRE GP, LLC, our general partner, owns all of our incentive distribution rights and an approximate 0.1% general partner interest in us. The following table sets forth the beneficial ownership of equity interests in our general partner.

Name of Beneficial Owner	**Class A Member Interest(1)**	**Class B Member Interest(1)**	**Class C Member Interest(1)**
Lime Rock Management LP(2) 274 Riverside Avenue, 3rd Floor Westport, CT 06880	100%		
Fund I(3)(4)		100%	
Fund II(3)(4)			100%

(1) Our general partner has three classes of member interests. LRR A, LRR B and LRR C own 14.2894%, 4.7376% and 80.9730%, respectively, of the Class B member interest in our general partner, which entitles them to an aggregate 80% of the distributions payable to our general partner with respect to the incentive distribution rights through November 16, 2017. In addition, Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. own 16.39% and 83.61%, respectively, of the Class C member interest in our general partner, which entitles them to an aggregate 20% of the distributions payable to our general partner with respect to the incentive distribution rights through November 16, 2017. After the six-year period, Lime Rock Management, as the Class A member, will be entitled to all distributions with respect to the incentive distribution rights in addition to the distributions with respect to our general partner s approximate 0.1% general partner interest in us.

(2) Our general partner is controlled by Lime Rock Management, which is ultimately controlled by Jonathan C. Farber, one of our general partner s directors, and John T. Reynolds. As ultimate control persons of our general partner, Mr. Farber and Mr. Reynolds will share in distributions made by us with respect to interests held by our general partner in proportion to their respective pecuniary interests. Mr. Farber and Mr. Reynolds, by virtue of their ownership interest in our general partner, may be deemed to beneficially own the interests held by our general partner. Each

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of Mr. Farber and Mr. Reynolds disclaims beneficial ownership of the reported securities in excess of his pecuniary interest in such securities. In addition, our general partner s other non-independent directors and certain of our general partner s executive officers have financial interests in Lime Rock Management and its general partner.

(3) Fund I is controlled indirectly by Jonathan C. Farber and John T. Reynolds, as indicated in footnote (3) to the table above. Fund II is controlled indirectly by Jonathan C. Farber and John T. Reynolds.

(4) The address for Fund I and Fund II is Heritage Plaza, 1111 Bagby Street, Suite 4600, Houston, Texas 77002.

Securities Authorized for Issuance under Equity Compensation Plan

The following table summarizes information about our equity compensation plans as of December 31, 2011:

Plan Category	**Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights**	**Weighted Average Exercise Price of Outstanding Options, Warrants and Rights**	**Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plan**
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders (1)	42,474	n/a	1,457,526

(1) Adopted by the board of directors of our general partner in connection with our initial public offering.

For a description of our equity compensation plan, please see the discussion under Item 11. Executive Compensation above.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Fund I owns 5,049,600 common units and 6,720,000 subordinated units representing an aggregate 52.4% limited partner interest in us and Lime Rock Resources, through its interest in our general partner, is entitled to receive 100% of the distributions we make with respect to our incentive distribution rights through November 16, 2017. In addition, our general partner owns an approximate 0.1% general partner interest in us, represented by 22,400 general partner units, and all of our incentive distribution rights. Furthermore, the non-independent directors and executive officers of our general partner, other than our general partner s Chief Financial Officer, serve in similar capacities with, and own economic interests, investments and other economic incentives in, Lime Rock Management, Lime Rock Resources and their affiliates.

In addition to the related transactions and relationships discussed below, information about such transactions and relationships is included in Note 9 of our Notes to Consolidated/Combined Financial Statements and is incorporated herein by reference in its entirety.

Distributions and Payments to Our General Partner and Its Affiliates

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

Operational Stage

Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 99.9% to our unitholders pro rata, including Fund I as the holder of approximately 52.4% of our limited partner interests, and 0.1% to our general partner, assuming it makes any capital contributions necessary to maintain its 0.1% general partner interest in us. In addition, if distributions

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	exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to a maximum of 23.1% of the distributions above the highest target distribution level, including the general partner s 0.1% general partner interest.
Payments to our general partner and its affiliates	Our general partner does not receive a management fee or other compensation for its management of our partnership, but we reimburse our general partner for all direct and indirect expenses it incurs and payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.
Withdrawal or removal of our general partner	In the event of removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the departing general partner s general partner interest and incentive distribution rights for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the departing general partner s general partner interest in us and its incentive distribution rights for their fair market value or to convert such interests into common units.

Liquidation Stage

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

Contribution Agreement

In connection with the closing of our IPO, we entered into a purchase, sale, contribution, conveyance and assumption agreement with Fund I pursuant to which Fund I sold and contributed the Partnership Properties to us. The underwriters partially exercised their option to purchase additional units and accordingly, on December 14, 2011, we issued an additional 1,200,000 units to the public. The net proceeds from the exercise of the underwriters option to purchase additional common units was used to pay additional cash consideration for the properties purchased from Fund I in connection with the IPO and to make additional distributions to Fund I.

Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and the assumption of $27.3 million of LRR A s indebtedness.

Services Agreement

On November 16, 2011, we entered into a services agreement with Lime Rock Management, OpCo, LRE GP, LLC (the General Partner) and the OLLC, pursuant to which Lime Rock Management and OpCo provides certain management, administrative and operating services and personnel to our general partner and us to manage and operate our business. Under the services agreement, our general partner reimburses Lime Rock Management and OpCo, on a monthly basis, for the allocable expenses they incur in their performance under the Services Agreement, and we reimburse our general partner for such payments it makes to Lime Rock Management and OpCo. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Lime Rock Management and OpCo to us. Lime Rock Management and OpCo have discretion to determine in good faith the proper allocation of costs and expenses to our general partner for their services. Lime Rock Management and OpCo will not be liable to us for their performance of, or failure to perform, services under the services agreement unless their acts or omissions constitute gross negligence or willful misconduct. During the period from the closing of our IPO though December 31, 2011, we reimbursed Lime Rock Management in the amount of $0.6 million for the expenses it incurred on our behalf pursuant to the services agreement.

Omnibus Agreement

On November 16, 2011, in connection with the closing of our IPO, we entered into an omnibus agreement (the Omnibus Agreement) with our General Partner, OLLC, LRR A, LRR B, LRR C, LRR GP, LLC and Lime Rock Management. Under the Omnibus Agreement, none of the parties or their respective affiliates have any obligation to offer, or provide any opportunity to pursue, purchase or invest in, any business opportunity to any other party or their affiliates. The Omnibus Agreement does not restrict any of the parties and their respective affiliates from competing with either Fund I or us, our general partner, the OLLC and all of their respective subsidiaries.

Pursuant to the Omnibus Agreement, each entity of Fund I indemnified us, our general partner, the OLLC and their respective subsidiaries against (i) title defects, (ii) income taxes attributable to pre-closing ownership or operation of the contributed assets, including any income tax liabilities related to the formation transactions that occurred on or prior to the closing of the IPO, (iii) environmental claims, losses and expenses associated with the operation of our business prior to the closing of the IPO, subject to a maximum of $10,000,000, (iv) all liabilities, other than liabilities covered under the preceding clause (iii) relating to the operation of the contributed assets prior to the closing that were not disclosed in the most recent pro forma balance sheet included in our Registration Statement on Form S-1, as amended (File No. 333-174017) or incurred in the ordinary course of business thereafter, and (v) losses resulting from the failure of Fund I to have on the closing date any consent, waiver or governmental permit that renders us, our general partner, the OLLC and their respective subsidiaries unable to own, use or operate the contributed assets in substantially the same manner as they were owned, used or operated immediately prior to the closing of the IPO.

Fund I s indemnification obligation (i) survives for three years after the closing of the IPO with respect to title defects, (ii) survives for one year after closing with respect to environmental claims, undisclosed liabilities and failure to have any consent, waiver or governmental permits, and (iii) terminates upon the earlier of (y) the expiration of the term of Fund I and (z) sixty days after the expiration of the applicable statute of limitations with respect to income taxes. All claims are subject to a $50,000 per claim de minimus exception, and no claims may be made against Fund I unless such losses exceed $500,000 in the aggregate; thereafter, each entity of Fund I will be liable, severally, in proportion to its contribution percentage, only to the extent that such losses exceed $500,000.

Long-Term Incentive Plan

On November 10, 2011, our general partner adopted the LRE GP, LLC Long-Term Incentive Plan (2011 LTIP) for employees, consultants and directors of our general partner and its affiliates, including Lime Rock Management and OpCo, who perform services for us. The 2011 LTIP consists of unit options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, unit awards and other unit-based awards. The 2011 LTIP initially limits the number of units that may be delivered pursuant to vested awards to 1,500,000 common units. The 2011 LTIP is administered by our general partner s board of directors or a committee thereof. During the period from the beginning of our IPO through December 31, 2011, we granted 42,474 restricted unit awards totaling $0.8 million under the 2011 LTIP.

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Review, Approval or Ratification of Transactions with Related Persons

The board of directors of our general partner has adopted a code of business conduct and ethics that provides that the board of directors of our general partner or its authorized committee will periodically review all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the board of directors of our general partner or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the code of business conduct and ethics provides that our management will make all reasonable efforts to cancel or annul the transaction.

The code of business conduct and ethics provides that, in determining whether or not to recommend the initial approval or ratification of a related person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: (i) whether there is an appropriate business justification for the transaction; (ii) the benefits that accrue to us as a result of the transaction; (iii) the terms available to unrelated third parties entering into similar transactions; (iv) the impact of the transaction on a director s independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediately family member of a director is a partner, shareholder, member or executive officer); (v) the availability of other sources for comparable products or services; (vi) whether it is a single transaction or a series of ongoing, related transactions; and (vii) whether entering into the transaction would be consistent with the code of business conduct and ethics.

The code of business conduct and ethics requires executive officers of our general partner to avoid conflicts of interest unless approved by the board of directors.

If a conflict or potential conflict of interest arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, the resolution of any such conflict or potential conflict will be addressed by the board in accordance with the provisions of our partnership agreement. The board of directors of our general partner has a standing conflicts committee comprised of entirely one or more independent directors. Our general partner may, but is not required to, seek the approval of the conflicts committee in connection with future acquisitions of oil and natural gas properties from Lime Rock Resources or its affiliates. In addition to acquisitions from Lime Rock Resources or its affiliates, the board of directors of our general partner will also determine whether to seek conflicts committee approval to the extent we act jointly to acquire additional oil and natural gas properties with Lime Rock Resources or its affiliates. In the case of any sale of equity or debt by us to an owner or affiliate of an owner of our general partner, we anticipate that our practice will be to obtain the approval of the conflicts committee of the board of directors of our general partner for the transaction. The conflicts committee will be entitled to hire its own financial and legal advisors in connection with any matters on which the board of directors of our general partner has sought the conflicts committee s approval.

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

We expect that Lime Rock Resources and its affiliates will consider a number of the same factors considered by the board of directors of our general partner to determine the proposed purchase price of any assets it may offer to us in future periods. In addition to these factors, given that

Lime Rock Resources, through Fund I, is our largest unitholder and through its interest in our general partner, will initially be entitled to 100% of the distributions with respect to the incentive distribution rights, Lime Rock Resources may consider the potential positive impact on its underlying investment in us by offering properties to us at attractive purchase prices. Likewise, Lime Rock Resources may consider the potential negative impact on its underlying investment in us if we are unable to acquire additional assets on favorable terms, including the negotiated purchase price.

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Director Independence

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

Distributions of Available Cash to Our General Partner and its Affiliates

We will generally make cash distributions to our unitholders and general partner pro rata, including our general partner and our affiliates. As of March 16, 2012, our general partner and its affiliates held 5,049,600 common units, 6,720,000 subordinated units and 22,400 general partner units. No cash distributions were made on the common unit, subordinated units and general partner units during the period from the closing of our IPO through December 31, 2011.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The audit committee of LRE GP, LLC selected PricewaterhouseCoopers LLP (PWC), an independent registered public accounting firm, to audit our consolidated financial statements for the year ended December 31, 2011.

Fees paid for audit and non-audit services to PWC are as follows (in thousands):

	Partnership	Predecessor	
	2011	2011	2010
Audit fees	$ 505	$ 200	$ 366
Audit-related fees	483		
Tax fees			
All other fees			
Total fees paid to PWC	$ 988	$ 200	$ 366

The audit committee s charter requires the audit committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. We did not have an audit committee prior to November 10, 2011; and as such, the services provided prior to that time were not approved by the audit committee.

The audit committee s pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other. In general, before we or any of our subsidiaries engage PWC to render a service, the engagement must be either (i) entered into pursuant to the audit committee s pre-approval policy or (ii) specifically approved by the audit committee. Requests or applications to provide services that require separate approval by the audit committee must be submitted to the audit committee by both PWC and our chief financial officer (or such officer s designee), and must include a joint statement as to whether, in their view, the request or application is consistent with the SEC s and the Public Company Accounting Oversight Board s rules on auditor independence. In connection with the audit committee s consideration of any proposed service, PWC, at the audit committee s request, will provide to the audit committee detailed documentation regarding the specific services to be provided so that the audit committee can make a well-reasoned assessment of the impact of the service on the auditor s independence.

In order for PWC to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, as well as any other service not permitted by the Public Company Accounting Oversight Board. The audit committee s pre-approval policy also precludes PWC from performing these and certain other services for us.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a)(1) Financial Statements

Our Consolidated/Combined Financial Statements are included under Part II, Item 8 of this Annual Report on Form 10-K. For a listing of these statements and accompanying footnotes, please read Index to Financial Statements on page F-1 of this Annual Report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

The following documents are filed as a part of this Annual Report on Form 10-K or incorporated by reference:

Exhibit Number	Description
3.1*	Certificate of Limited Partnership of LRR Energy, L.P. dated as of April 28, 2011 (incorporated by reference to Exhibit 3.1 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.2	First Amended and Restated Agreement of Limited Partnership of LRR Energy, L.P. dated as of November 16, 2011.
3.3*	Certificate of Formation of LRE GP, LLC dated as of April 28, 2011 (incorporated by reference to Exhibit 3.4 to the Partnership s Registration Statement on Form S-1 (SEC File No. 333-174017), filed on May 6, 2011).
3.4*	Amended and Restated Limited Liability Company Agreement of LRE GP, LLC dated as of November 16, 2011 (incorporated by reference to Exhibit 3.2 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
10.1*	Stakeholders Agreement, dated effective as of May 5, 2011, by and among LRR Energy, L.P., LRE GP, LLC, Lime Rock Resources GP, L.P., Lime Rock Resources A, L.P., Lime Rock Resources B, L.P., Lime Rock Resources C, L.P., Lime Rock Management LP, Lime Rock Resources GP II, L.P., Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. (incorporated by reference to Exhibit 10.7 to the Partnership s Registration Statement on Form S-1 (Registration No. 333-174017) filed on May 6, 2011).

10.2*	Credit Agreement, dated as of July 22, 2011, among LRE Operating, LLC, as Borrower, LRR Energy, L.P., as Parent Guarantor, the lenders from time to time party thereto, Wells Fargo Bank, National Association, as Administrative Agent, Bank of America, N.A., as Syndication Agent, and BNP Paribas, Citibank, N.A. and Royal Bank of Canada, as Co-Documentation Agents (incorporated by reference to Exhibit 10.3 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
10.3*	First Amendment to Credit Agreement, dated as of September 30, 2011, among LRE Operating, LLC, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.4 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
10.4*	Omnibus Agreement, dated as of November 16, 2011, by and among LRR Energy, L.P., LRE GP, LLC, LRE Operating, LLC, LRR GP, LLC, Lime Rock Resources A, L.P., Lime Rock

	Resources B, L.P., Lime Rock Resources C, L.P. and Lime Rock Management LP (incorporated by reference to Exhibit 10.1 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
10.5*	Services Agreement, dated as of November 16, 2011, by and among Lime Rock Management LP, Lime Rock Resources Operating Company, Inc., LRE GP, LLC, LRR Energy, L.P. and LRE Operating, LLC (incorporated by reference to Exhibit 10.2 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
10.6*	Purchase, Sale, Contribution, Conveyance and Assumption Agreement, dated as of November 16, 2011, by and among Lime Rock Resources A, L.P., Lime Rock Resources B, L.P., Lime Rock Resources C, L.P., LRE GP, LLC, LRR Energy, L.P. and LRE Operating, LLC (incorporated by reference to Exhibit 10.5 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 22, 2011).
10.7*	Amended and Restated Purchase, Sale, Contribution, Conveyance and Assumption Agreement, dated effective as of November 16, 2011, by and among Lime Rock Resources A, L.P., Lime Rock Resources B, L.P., Lime Rock Resources C, L.P., LRE GP, LLC, LRR Energy, L.P. and LRE Operating, LLC (incorporated by reference to Exhibit 10.6 to the Partnership s Quarterly Report on Form 10-Q (SEC File No. 001-35344), filed on December 20, 2011.
10.8*#	LRE GP, LLC Long-Term Incentive Plan, adopted as of November 10, 2011 (incorporated by reference to Exhibit 10.1 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 16, 2011).
10.9*#	Form of Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.2 to the Partnership s Current Report on Form 8-K (SEC File No. 001-35344), filed on November 16, 2011).
21.1	List of Subsidiaries of LRR Energy, L.P.
23.1	Consent of PricewaterhouseCoopers LLP
23.2	Consent of Miller and Lents, Ltd.
23.3	Consent of Netherland, Sewell and Associates, Inc.
31.1	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
31.2	Certification by Co-Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
31.3	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934.
32.1	Certification by Co-Chief Executive Officers and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of Miller and Lents, Ltd.
99.2	Report of Netherland, Sewell and Associates, Inc.
101.INS**	XBRL Instance Document.

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101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

* Incorporated by reference

** Submitted electronically herewith

Compensatory plan or arrangement

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 27th day of March, 2012.

LRR ENERGY, L.P.

By: LRE GP, LLC,
its general partner

By: /s/ ERIC MULLINS
Name: Eric Mullins
Title: Co-Chief Executive Officer and Chairman
(Principal Executive Officer)

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

Signature	Title	Date
/s/ ERIC MULLINS Eric Mullins	Co-Chief Executive Officer and Chairman (Principal Executive Officer)	March 27, 2012
/s/ CHARLES W. ADCOCK Charles W. Adcock	Co-Chief Executive Officer and Director (Principal Executive Officer)	March 27, 2012
/s/ JAIME R. CASAS Jaime R. Casas	Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)	March 27, 2012
/s/ DON T. NGUYEN Don T. Nguyen	Chief Accounting Officer (Principal Accounting Officer)	March 27, 2012
/s/ JONATHAN C. FARBER Jonathan C. Farber	Director	March 27, 2012
/s/ TOWNES G. PRESSLER, JR. Townes G. Pressler, Jr.	Director	March 27, 2012
/s/ JOHN A. BAILEY John A. Bailey	Director	March 27, 2012
/s/ MILTON CARROLL Milton Carroll	Director	March 27, 2012
/s/ ROBERT T. O CONNELL Robert T. O Connell	Director	March 27, 2012

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INDEX TO CONSOLIDATED/COMBINED FINANCIAL STATEMENTS

LRR ENERGY, L.P. AUDITED CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

To the Board of Directors of LRE GP, LLC and Unitholders of LRR Energy, L.P.:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statement of operations, changes in unitholders equity and cash flows present fairly, in all material respects, the financial position of LRR Energy, L.P. and its subsidiary (the Partnership) at December 31, 2011 and the results of their operations and their cash flows for the period from November 16, 2011 to December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Houston, Texas

March 27, 2012

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Report of Independent Registered Public Accounting Firm

To the Board of Directors of LRE GP, LLC and Unitholders of LRR Energy, L.P.:

In our opinion, the accompanying combined balance sheet and the related combined statement of operations, changes in partners capital and cash flows present fairly, in all material respects, the financial position of Fund I (the Predecessor) at December 31, 2010 and the results of their operations and their cash flows for the period from January 1, 2011 to November 15, 2011 and for each of the two years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Predecessor s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Houston, Texas

March 27, 2012

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LRR Energy, L.P.

Balance Sheets

(in thousands, except unit amounts)

	Partnership December 31, 2011 (consolidated)	Predecessor December 31, 2010 (combined)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,513	$ 12,455
Accounts receivable:		
Oil and natural gas sales	11,801	14,012
Trade and other	1,123	2,531
Commodity derivative instruments	16,064	23,819
Amounts due from affiliates		59
Prepaid expenses	578	1,722
Total current assets	31,079	54,598
Property and equipment (successful efforts method)	644,188	784,346
Accumulated depletion, depreciation and impairment	(245,581)	(342,400)
Total property and equipment, net	398,607	441,946
Commodity derivative instruments	27,015	7,767
Deferred financing costs, net of accumulated amortization	1,365	311
TOTAL ASSETS	$ 458,066	$ 504,622
LIABILITIES AND UNITHOLDERS EQUITY		
Current liabilities:		
Trade accounts payable	$ 2,707	$ 3,354
Accrued liabilities	2,739	8,141
Accrued capital cost	1,421	6,620
Commodity derivative instruments	186	1,888
Due to affiliates	536	
Interest rate derivative instruments		594
Asset retirement obligations	359	792
Total current liabilities	7,948	21,389
Long-term liabilities:		
Commodity derivative instruments		5,333
Interest rate derivative instruments		267
Revolving credit facility	155,800	27,251
Asset retirement obligations	22,780	23,504
Deferred tax liabilities	35	145
Total long-term liabilities	178,615	56,500
Total liabilities	186,563	77,889
Contractual obligations and commitments (Note 13)		

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LRR Energy, L.P.

Balance Sheets

(in thousands, except unit amounts)

(continued)

	Partnership December 31, 2011 (consolidated)	Predecessor December 31, 2010 (combined)
Unitholders equity:		
Predecessor partners capital	$	$ 426,733
General partner (22,400 units issued and outstanding as of December 31, 2011)	438	
Public common unitholders (10,608,000 units issued and outstanding as of December 31, 2011)	189,537	
Affiliated common unitholders (5,049,600 units issued and outstanding as of December 31, 2011)	35,007	
Subordinated unitholders (6,720,000 units issued and outstanding as of December 31, 2011)	46,521	
Total unitholders equity	271,503	426,733
TOTAL LIABILITIES AND UNITHOLDERS EQUITY	$ 458,066	$ 504,622

See accompanying notes to the consolidated/combined financial statements.

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LRR Energy, L.P.

Statements of Operations

(in thousands, except per unit amounts)

	Partnership November 16 to December 31, 2011 (consolidated)	January 1 to November 15, 2011	Predecessor Year ended December 31, 2010 (combined)	2009
Revenues:				
Oil sales	$ 6,118	$ 59,605	$ 52,670	$ 34,604
Natural gas sales	3,482	35,883	48,088	33,798
Natural gas liquids sales	1,567	14,500	14,748	10,617
Realized gain on commodity derivative instruments	4,015	9,353	48,029	70,902
Unrealized gain (loss) on commodity derivative instruments	6,664	12,674	(23,964)	(62,375)
Other income		159	116	24
Total revenues	21,846	132,174	139,687	87,570
Operating Expenses:				
Lease operating expense	2,441	21,391	23,804	19,066
Production and ad valorem taxes	850	7,763	9,320	6,731
Depletion and depreciation	3,923	37,206	55,828	56,349
Impairment on oil and natural gas properties		16,765	11,712	
Accretion expense	168	1,290	1,366	1,255
(Gain) loss on settlement of asset retirement obligations		496	(209)	(1,570)
Management fees		5,435	6,104	8,500
General and administrative expense	1,662	5,149	5,293	2,408
Total operating expenses	9,044	95,495	113,218	92,739
Operating income (loss)	12,802	36,679	26,469	(5,169)
Other income (expense), net				
Interest income		1	17	87
Interest expense	(604)	(919)	(3,223)	(1,274)
Realized loss on interest rate derivative instruments		(574)	(649)	(457)
Unrealized gain (loss) on interest rate derivative instruments		441	(248)	95
Other income (expense), net	(604)	(1,051)	(4,103)	(1,549)
Income (loss) before taxes	12,198	35,628	22,366	(6,718)
Income tax benefit (expense)	(48)	76	(32)	622
Net income (loss)	$ 12,150	35,704	$ 22,334	$ (6,096)
Computation of net income per limited partner unit:				
General partners interest in net income	$ 12			

Limited partners interest in net income	$	12,138
Net income per limited partner unit	$	0.54
Weighted average number of limited partner units outstanding		22,418

See accompanying notes to the consolidated/combined financial statements.

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LRR Energy, L.P.

Consolidated Statement of Changes in Unitholders Equity

(in thousands)

			Limited Partners		
			Affiliated		
	General Partner	Public Common	Common	Subordinated	Total
Balance, November 16, 2011	$	$	$	$	$
Book value of net assets contributed by the predecessor (Note 1)			165,899	220,462	386,361
Initial public offering (Note 1)		188,451			188,451
Transaction costs		(4,716)			(4,716)
Contributions from general partner	426				426
Amortization of equity awards		31			31
Distribution to Fund I (Note 1)			(133,626)	(177,574)	(311,200)
Net income	12	5,771	2,734	3,633	12,150
Balance, December 31, 2011	$ 438	$ 189,537	$ 35,007	$ 46,521	$ 271,503

See accompanying notes to the consolidated/combined financial statements.

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Predecessor-Fund I

Combined Statements of Changes in Partners Capital

(in thousands)

	General Partner	Limited Partners	Class B Limited Partner	Total
Balance, December 31, 2008	$ 4,460	$ 334,574	$ 182,750	$ 521,784
Capital contributions	48	12,629	5,100	17,777
Distributions	(844)	(63,208)	(59,934)	(123,986)
Capital contributions returned	(50)	(3,783)		(3,833)
Net loss	(78)	(6,018)		(6,096)
Balance, December 31, 2009	3,536	274,194	127,916	405,646
Capital contributions	1,054	79,064	48,849	128,967
Distributions	(1,057)	(79,249)	(40,590)	(120,896)
Capital contributions returned	(123)	(9,195)		(9,318)
Net income	42	3,294	18,998	22,334
Balance, December 31, 2010	3,452	268,108	155,173	426,733
Capital contributions	70	5,283		5,353
Distributions	(471)	(35,295)	(7,587)	(43,353)
Net income	487	27,630	7,587	35,704
Balance, November 15, 2011	$ 3,538	$ 265,726	$ 155,173	$ 424,437

See accompanying notes to the consolidated/combined financial statements.

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LRR Energy, L.P.

Statements of Cash Flows

(in thousands)

	Partnership November 16 to December 31, 2011 (consolidated)	January 1 to November 15, 2011	Predecessor Year ended December 31, 2010 (combined)	2009
CASH FLOWS FROM OPERATING ACTIVITES				
Net income (loss)	$ 12,150	$ 35,704	$ 22,334	(6,096)
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depletion and depreciation	3,923	37,206	55,828	56,349
Impairment of oil and natural gas properties		16,765	11,712	
Unrealized loss (gain) on derivative instruments, net	(6,664)	(13,115)	24,212	62,280
Accretion expense	168	1,290	1,366	1,255
Amortization of equity awards	31			
Amortization of deferred financing costs	50	59	138	117
Deferred tax provision				(661)
(Gain) loss on settlement of asset retirement obligations		496	(209)	(1,570)
Changes in operating assets and liabilities				
Change in oil and natural gas sales	(11,801)	5,159	(2,055)	4,009
Change in trade and other	(1,123)	(3,448)	487	5,567
Change in prepaid expenses	(578)	357	4,493	(5,807)
Change in trade accounts payable	2,707	4,292	1,030	(4,188)
Change in amounts due from affiliates	536	1,114	653	(387)
Change in accrued liabilities	2,739	(1,771)	1,280	(2,720)
Change in deferred tax liability	35	(81)		
Net cash provided by operating activities	2,173	84,027	121,269	108,148
CASH FLOWS FROM INVESTING ACTIVITIES				
Acquisition of oil and natural gas properties	(14)	(392)	(105,209)	(8,514)
Development of oil and natural gas properties	(741)	(47,410)	(33,069)	(19,645)
Disposition of oil and natural gas properties		2,956	12,553	3,144
Expenditures for other property and equipment		(45)	(121)	(114)
Net cash used in investing activities	$ (755)	$ (44,891)	$ (125,846)	$ (25,129)

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LRR Energy, L.P.

Statements of Cash Flows

(in thousands)

(Continued)

	Partnership November 16 to December 31, 2011 (consolidated)	January 1 to November 15, 2011	Predecessor Year ended December 31, 2010 (combined)	2009
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from IPO	$ 188,451	$	$	$
Contribution by general partner	426			
Transaction costs	(4,716)			
Deferred financing costs	(1,415)		(349)	(9)
Borrowings under revolving credit facility	155,800		8,620	900
Principal payments on revolving credit facility	(27,251)		(5,519)	(9,000)
Capital contributions		5,353	128,967	17,777
Distributions	(311,200)	(43,353)	(120,896)	(123,986)
Capital contributions returned			(9,318)	(3,833)
Net cash provided by (used in) financing activities	95	(38,000)	1,505	(118,151)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,513	1,136	(3,072)	(35,132)
CASH AND CASH EQUIVALENTS, BEGINNING OF THE PERIOD		12,455	15,527	50,659
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 1,513	$ 13,591	$ 12,455	$ 15,527
Supplemental disclosure of cash flow information				
Cash paid for taxes during the period	$	$ 603	$ 25	$ 149
Cash paid for interest during the period	31	4	928	1,382
Supplemental disclosure of non-cash items to reconcile investing and financing activities				
Property and equipment:				
Accrued capital costs	(1,421)	5,791	2,938	323
Asset retirement obligations	(298)	(241)	3,736	925

See accompanying notes to the consolidated/combined financial statements.

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LRR Energy, L.P.

Notes to Consolidated/Combined Financial Statements

1. Organization and Description of Business

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. As used herein, references to Fund I or predecessor refer collectively to LRR A, LRR B and LRR C. References to Lime Rock Resources refer collectively to LRR A, LRR B, LRR C, Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. The properties conveyed to us in connection with our initial public offering (IPO) (such conveyance described below) 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. We conduct our operations through our wholly owned subsidiary, LRE Operating, LLC (OLLC).

Prior to our IPO, Fund I owned 100% of the properties conveyed to us in connection with our IPO. On November 16, 2011, we completed our IPO of 9,408,000 common units representing limited partner interests in the Partnership at a price to the public of $19.00 per common unit, or $17.8125 per common unit after payment of the underwriting discount. Total net proceeds from the sale of common units in our IPO were $167.2 million ($178.8 million less $11.2 million for the underwriting discount and a $0.4 million structuring fee). IPO costs were approximately $4.7 million. Net proceeds of the offering, along with $155.8 million of borrowings under our new $500 million senior secured revolving credit agreement (Note 7) were utilized to make cash distributions and payments to Fund I of approximately $289.9 million and repay $27.3 million of LRR A s debt that we assumed at closing.

On December 14, 2011, we closed the partial exercise of the underwriters option to purchase additional units and as a result issued an additional 1,200,000 common units to the public. The net proceeds ($21.3 million) from the exercise of the underwriters option to purchase additional common units was used to pay additional cash consideration for the properties purchased from Fund I in connection with the IPO and to make additional distributions to Fund I.

At the closing of our IPO, we entered into a purchase, sale, contribution, conveyance and assumption agreement with Fund I pursuant to which Fund I sold and contributed to us specified oil and natural gas properties and related net profits interests and operations and certain commodity derivative contracts (the Partnership Properties). Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and the assumption of $27.3 million of LRR A s indebtedness.

After reviewing applicable accounting literature, we consider the Partnership Properties to be under common control with Fund I. We have presented the combined historical financial statements of Fund I as our historical financial statements because we believe them to be informative to our investors and representative of our management s ability to manage the Partnership Properties. The financial data and operations of Fund I are referred to herein as predecessor.

The following table presents the net assets conveyed by Fund I to the Partnership immediately prior to the closing of IPO including the debt assumption (in thousands):

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Property and equipment, net	$	400,056
Derivative instruments		36,705
Total assets	$	436,761
Long-term debt	$	27,251
Derivative instruments		476
Asset retirement obligations		22,673
Total liabilities	$	50,400
Net assets	$	386,361

In connection with our IPO, we also restated or entered into the following agreements:

Amended and Restated Agreement of Limited Partnership. We amended and restated our agreement of limited partnership which provides, among other things, for registration rights for the benefit of our general partner and Fund I.

Amended and Restated Limited Liability Company Agreement of our General Partner. Our general partner also amended and restated its limited liability company agreement. The amendments to the agreement included provisions regarding, among other things, the issuance of additional classes of membership interests, the rights of the members of the general partner, distributions and allocations and management by the board of directors of our general partner.

Credit Agreement. Please refer to Note 7 for a description of our credit agreement.

Services Agreement. We entered into a services agreement (the Services Agreement) by and among Lime Rock Management, Lime Rock Resources Operating Company, Inc. (OpCo), LRE GP, LLC (the General Partner), the Partnership and the OLLC, pursuant to which Lime Rock Management and OpCo provide certain management, administrative and operating services and personnel to our general partner and us to manage and operate our business. Under the Services Agreement, our general partner reimburses Lime Rock Management and OpCo, on a monthly basis, for the allocable expenses they incur in their performance under the Services Agreement, and we reimburse our general partner for such payments it makes to Lime Rock Management and OpCo. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Lime Rock Management and OpCo to us. Lime Rock Management and OpCo have discretion to determine in good faith the proper allocation of costs and expenses to our general partner for their services. Lime Rock Management and OpCo will not be liable to us for their performance of, or failure to perform, services under the Services Agreement unless their acts or omissions constitute gross negligence or willful misconduct. Please refer to Note 9 for amounts paid to affiliates.

Omnibus Agreement. We entered into an omnibus agreement (the Omnibus Agreement) with our general partner, the OLLC, LRR A, LRR B, LRR C, LRR GP, LLC and Lime Rock Management. Under the Omnibus Agreement, none of the parties or their respective affiliates have any obligation to offer, or provide any opportunity to pursue, purchase or invest in, any business opportunity to any other party or their affiliates. The Omnibus Agreement does not restrict any of the parties and their respective affiliates from competing with either Fund I or us, our general partner, the OLLC and all of their respective subsidiaries.

Pursuant to the Omnibus Agreement, each entity of Fund I indemnified us, our general partner, the OLLC and their respective subsidiaries against (i) title defects, (ii) income taxes attributable to pre-closing ownership or operation of the contributed assets, including any income tax liabilities related to the formation transactions that occurred on or prior to the closing of the IPO, (iii) environmental claims, losses and expenses associated with the operation of our business prior to the closing of the IPO, subject to a maximum of $10,000,000, (iv) all liabilities, other than liabilities covered under the preceding clause, (iii) relating to the operation of the contributed assets prior to the closing that were not disclosed in the most recent pro forma balance sheet included in our Registration Statement on Form S-1, as amended (File No. 333-174017) or incurred in the ordinary course of business thereafter,

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and (v) losses resulting from the failure of Fund I to have on the closing date any consent, waiver or governmental permit that renders us, general partner, the OLLC and their respective subsidiaries unable to own, use or operate the contributed assets in substantially the same manner as they were owned, used or operated immediately prior to the closing of the IPO.

Fund I s indemnification obligation (i) survives for three years after the closing of the IPO with respect to title defects, (ii) survives for one year after closing with respect to environmental claims, undisclosed liabilities and failure to have any consent, waiver or governmental permits, and (iii) terminates upon the earlier of (y) the expiration of the term of Fund I and (z) sixty days after the expiration of the applicable statute of limitations with respect to income taxes. All claims are subject to a $50,000 per claim de minimus exception, and no claims may be made against Fund I unless such losses exceed $500,000 in the aggregate; thereafter, each entity of Fund I will be liable, severally, in proportion to its contribution percentage, only to the extent that such losses exceed $500,000.

Long-Term Incentive Plan. Please refer to Note 12 for a description on our Long-Term Incentive Plan.

2. Summary of Significant Accounting Policies

Basis of presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2011 and the predecessor s combined financial position as of December 31, 2010. These financial statements include the results of our operations, cash flows and changes in unitholder s equity for the period of November 16 to December 31, 2011. The financial statements also include the results of our predecessor s operations, cash flows and changes in partner s capital for the period of January 1 to November 15, 2011 and the years ended December 31, 2010 and 2009. The combined financial statements of Fund I reflect the predecessor financial statements of the Partnership and have been prepared from the separate financial records maintained by Fund I. Because the results of our predecessor include results for both the properties conveyed to us in connection with our IPO and properties retained by our predecessor, we do not consider these results of our predecessor to be indicative of our future results.

These consolidated/combined financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and all intercompany transactions and account balances have been eliminated. We operate oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas. Our management evaluates performance based on one business segment as there are not different economic environments within the operation of the oil and natural gas properties.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

Depreciation, depletion and amortization of oil and natural gas properties and the impairment of oil and natural gas properties are determined using estimates of oil and natural gas reserves. There are numerous uncertainties in estimating the quantity of reserves and in projecting the future rates of production and timing of development expenditures, including future costs to dismantle, dispose, and restore our properties. Oil and natural gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way.

Cash and cash equivalents

We consider all highly liquid instruments purchased with a maturity when acquired of three months or less to be cash equivalents. We continually monitor our positions with, and the credit quality of, the financial institutions with which we invest.

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Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. We use the specific identification method of providing allowances for doubtful accounts. At December 31, 2011 and 2010, we did not have an allowance for doubtful accounts.

Revenue recognition

Revenues from oil and gas sales are recognized based on the sales method with revenue recognized on actual volumes sold to purchasers. Under this method of revenue recognition, a gas imbalance is created if the quantity sold is greater than or less than our entitlement share in any particular period. To the extent there are sufficient quantities of natural gas remaining to make up the gas imbalance, oil and natural gas reserves are adjusted to reflect the overproduced or underproduced position. In situations where there are insufficient reserves available to make up an overproduced imbalance, a liability is established. As of December 31, 2011 and 2010, we had no significant production imbalances.

Concentrations of credit and significant customers

Financial instruments which potentially subject us to credit risk consist principally of cash balances, accounts receivable and derivative financial instruments. We maintain cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. We have not experienced any significant losses from such investments. We attempt to limit the amount of credit exposure to any one financial institution or company through procedures that include credit approvals, credit limits and terms, letters of credit, prepayments and rights of offset. Our customer base consists primarily of major integrated and international oil and natural gas companies, as well as smaller processors and gatherers. We believe the credit quality of our customer base is high and have not experienced significant write-downs in our accounts receivable balances.

For the period from November 16 to December 31, 2011, purchases by ConocoPhillips, Seminole Energy Services and Upstream Energy accounted for 25%, 16% and 12%, respectively, of our total sales revenues.

For the period from January 1 to November 15, 2011, purchases by ConocoPhillips, Seminole Energy Services and Sunoco accounted for 18%, 12% and 16%, respectively, of our predecessor s total sales revenues.

For the year ended December 31, 2010, purchases by ConocoPhillips, Seminole Energy Services, Upstream Energy, and Sunoco accounted for 16%, 13%, 10% and 10%, respectively, of our predecessor s total sales revenues.

For the year ended December 31, 2009, purchases by Upstream Energy, ConocoPhillips, Square Mile Energy, and Sunoco accounted for 18%, 14%, 13% and 11%, respectively, of our predecessor s total sales revenues.

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

Oil and natural gas properties

Proved properties. We account for our oil and natural gas exploration, development and production activities in accordance with the successful efforts method. Under 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 potential 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. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows are less than net book value.

For the period from January 1 to November 15, 2011, the predecessor recorded non-cash impairment charges on proved oil and natural gas properties of $16.8 million. For the year ended December 31, 2010, the predecessor recorded non-cash impairment charges on proved oil and natural gas properties of $10.9 million. These charges are included in impairment of oil and natural gas properties on the consolidated/combined statements of operations. No impairment was recorded for proved properties for the period from November 16 to December 31, 2011 or the year ended December 31, 2009. Refer to Note 5 for additional information.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization 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 proved 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.

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. As of December 31, 2011 and 2010, $1.4 million and $2.1 million, respectively, of oil and natural gas property costs were related to unproved leasehold acquisitions costs and not subject to depletion. For the year to date period ending November 15, 2011 and the year ended December 31, 2010, the predecessor reclassified $0.3 million and $0.2 million, respectively, from unproved to proved properties. We did not reclassify any material amounts from unproved to proved properties during the period from November 16 to December 31, 2011.

We assess unproved properties for impairment on a quarterly basis. For the year ended December 31, 2010, the predecessor recorded an impairment charge for unproved properties in the amount of $0.8 million. No impairments were recorded for unproved properties during 2011 or 2009. The impairments were based on 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 subject to additional project-specific risk factors.

Other property and equipment

Other property and equipment is stated at historical cost less accumulated depreciation expense and is comprised primarily of software, computers and office equipment. Depreciation is calculated using the straight-line method based on useful lives of the assets ranging from three to five years. Other property and equipment is evaluated for impairment as necessary to determine if current circumstances and market conditions indicate that the carrying amounts of assets may not be recoverable. We did not recognize any impairment loss related to other property and equipment during 2011, 2010 and 2009.

Asset retirement obligations

We have obligations under our lease agreements and federal regulations to remove equipment and restore land at the end of oil and natural gas production operations. These asset retirement obligations (ARO) are primarily associated with plugging and abandoning wells. Determining the future restoration and removal requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. We follow the guidance in ASC Topic 410, Asset Retirement and Environmental Obligations which requires entities to record the fair value of a liability for an ARO in the period in which it is incurred with a

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corresponding increase in the carrying amount of the related long-lived asset. We typically incur this liability upon acquiring or drilling a well. Over time, the liability is accreted each period toward its future value, and the capitalized cost is depleted as a component of development costs. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability.

Inherent to the present value calculation are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. Increases in the discounted retirement obligation liability and related oil and natural gas assets resulting from the passage of time will be reflected as additional accretion and depreciation expense in the combined statements of operations.

Derivatives

Our activities primarily consist of acquiring, owning, enhancing and producing oil and natural gas properties. The future results of our operations, cash flows and financial condition may be affected by changes in the market price of oil and natural gas. The availability of a ready market for oil and natural gas products in the future will depend on numerous factors beyond our control, including weather, imports, marketing of competitive fuels, proximity and capacity of oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of oil, natural gas and liquid products, the regulatory environment, the economic environment and, other regional and political events, none of which can be predicted with certainty.

In order for us to manage our exposure to oil and natural gas price volatility, we enter into commodity derivative instruments such as futures contracts, swaps, or options. We are also exposed to changes in interest rates, primarily as a result of variable rate borrowings under the credit facility. In an effort to reduce this exposure, we have, from time to time, entered into derivative contracts (interest rate swaps) to mitigate the risk of interest rate fluctuations. For commodity derivatives, both realized and unrealized gains and losses are recorded as separate components of revenues. For interest rate derivatives, both realized and unrealized gains and losses are recorded as a component of other income (expense) in the consolidated/combined statements of operations.

ASC Topic 815, Derivatives and Hedging, requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. Realized gains and losses on derivative hedging instruments are recorded currently in earnings. Unrealized gains and losses on derivatives are also recorded currently in earnings unless the derivatives qualify and are appropriately designated as hedges. Unrealized gains or losses on derivative instruments that qualify and are designated as hedges are deferred in other comprehensive income until the related transaction occurs. We have not designated any of its derivative instruments as hedges. As a result, we mark our derivative instruments to fair value in accordance with the provisions of ASC Topic 815 and recognize the changes in fair market value in earnings. Refer to Note 8 for additional information.

Derivative financial instruments are generally executed with major financial institutions that expose us to market and credit risks and which may, at times, be concentrated with certain counterparties or groups of counterparties. All of our derivatives at December 31, 2011 are with parties that are also lenders under our credit facility. The credit worthiness of the counterparties is subject to continual review. We monitor the nonperformance risk of itself and of each of our counterparties and assesses the possibility of whether each counterparty to the derivative contract would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. We also have netting arrangements in place with each counterparty to reduce credit exposure.

Equity-based compensation

We have granted restricted unit awards which we account for at fair value. Restricted unit awards, net of estimated forfeitures, are expensed over the requisite service period. As each award vests, an adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the

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vested awards. We record these compensation costs as general and administrative expenses. Refer to Note 12 for additional information.

Income taxes

We are not taxable for federal income tax purposes and do not directly pay federal income tax. Generally, all of our taxable federal income and losses are reported on the income tax returns of our unitholders or partners, and therefore, no provision for federal income taxes has been recorded in our accompanying consolidated/combined financial statements.

We record our obligations under the Texas gross margin tax as Income tax in the consolidated/combined statements of operations. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period of rate change.

Deferred financing costs

Costs incurred in connection with the execution or modification of our credit facility are capitalized and amortized using the effective interest method over the term of the credit facility.

Recent accounting pronouncements

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities. The amendments in this update require enhanced disclosures around financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. We do not expect this guidance to have any impact on our consolidated financial position, results of operations or cash flows.

3. Acquisitions and Divestitures

We did not acquire or divest any significant properties during 2011. We acquire proved oil and natural gas properties that meet management s criteria with respect to reserve lives, development potential, production risk and other operational characteristics. We generally do not acquire assets other than oil and natural gas property interests. We assume the liability for ARO related to each acquisition and record the liability at fair value as of the date of closing.

The operating revenues and expenses of acquired properties are included in the predecessor s combined financial statements from the acquisition date. Transactions are financed through partner contributions and borrowings.

The acquisitions discussed below were accounted for under the acquisition method of accounting. Accordingly, we conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while acquisition costs associated with the acquisitions were expensed as incurred.

The fair values of oil and natural gas properties and ARO are 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 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.

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Summarized below are the combined results of operations of our predecessor for the periods presented, on an unaudited pro forma basis, as if the 2010 and 2009 acquisitions had occurred on January 1, 2009 (in thousands):

	Year ended December 31, 2010		Year ended December 31, 2009	
	Actual	**Pro Forma**	**Actual**	**Pro Forma**
Revenue	$ 139,687	$ 145,193	$ 87,570	$ 126,087
Net income (loss)	$ 22,334	$ 26,494	$ (6,096)	$ 26,483

Acquisitions 2010

The following table summarizes the values assigned to the assets acquired and liabilities assumed for the year ended December 31, 2010 as of the acquisition dates (in thousands):

	Potato Hills	**Other Acquisitions**	**Total-2010 Acquisitions**
Oil and natural gas properties	$ 97,488	$ 7,721	$ 105,209
Asset retirement obligations assumed	(1,927)	(1,067)	(2,994)
Identifiable net assets	$ 95,561	$ 6,654	$ 102,215

These acquisitions qualify as business combinations, and as such, the predecessor estimated the fair value of these properties as of the acquisition dates. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. In the estimation of fair value, we used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed under Note 4. After post-closing and title adjustments, the assets acquired and liabilities assumed approximate fair value for the acquisitions.

Significant acquisition Potato Hills. On February 23, 2010, the predecessor completed an acquisition of interests in 51 producing gas wells located in Oklahoma (Potato Hills) from a private independent oil and gas company for approximately $104.0 million in cash, subject to customary post-closing and title adjustments. Total proved reserves of the acquired properties were estimated at 10.0 million barrels of oil equivalent at the date of the acquisition.

Other acquisitions. On August 31, 2010, the predecessor completed the acquisition of certain oil and natural gas properties located in Texas from a private independent oil and gas company for a purchase price of approximately $7.5 million, subject to customary post-closing and title adjustments.

On October 14, 2010, the predecessor also closed the acquisition of an additional interest in certain New Mexico wells in which it already held interests from a large public independent oil and gas company. The acquisition was valued at $1.8 million, subject to customary post-closing and title adjustments, and was in partial consideration for the divestiture of certain other New Mexico properties as discussed below under Divestitures of non-core assets 2010 and 2009 .

Acquisitions 2009

The following table summarizes the values assigned to the assets acquired and liabilities assumed for the year ended December 31, 2009 as of the acquisition dates (in thousands):

		Total-2009 Acquisitions
Oil and natural gas properties	$	8,514
Asset retirement obligations assumed		(797)
Identifiable net assets	$	7,717

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On July 17, 2009, the predecessor completed the acquisition of certain oil and natural gas properties located in New Mexico from a large public independent oil and gas company for a purchase price of approximately $3.7 million, subject to customary post-closing and title adjustments.

On December 2, 2009, the predecessor completed the acquisitions of certain oil and natural gas properties located in DeWitt County, Texas from a private independent oil and gas company for an aggregate purchase price of approximately $6.1 million, subject to customary post-closing and title adjustments.

Divestitures of non-core assets 2010 and 2009

During 2010, the predecessor sold its interests in certain oil and natural gas properties located in New Mexico with carrying values of approximately $14.3 million and received net cash proceeds of approximately $12.5 million and certain additional property interests valued at $1.8 million.

During 2009, the predecessor sold its interests in certain oil and natural gas properties in Texas for $3.2 million, subject to customary post-closing adjustments.

In both 2010 and 2009, the sales of these non-core assets did not affect the unit-of-production amortization rate and, therefore, no gain or loss was recognized for the divestitures.

4. Fair Value Measurements

Our financial instruments, including cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. Our financial and non-financial assets and liabilities that are measured on a recurring basis are measured and reported at fair value.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of fair value hierarchy are as follows:

Level 1 Defined as inputs such as unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 Defined as inputs other than quoted prices in active markets that are either directly or indirectly observable for the asset or liability.

Level 3 Defined as unobservable inputs for use when little or no market data exists, requiring an entity to develop its own assumptions for the asset or liability.

As required by GAAP, we utilize the most observable inputs available for the valuation technique used. The financial assets and liabilities are classified in their entirety based on the lowest level of input that is of significance to the fair value measurement. The following table describes, by level within the hierarchy, the fair value of our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and December 31, 2010 (in thousands).

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	Level 1	Level 2	Level 3	Total
Partnership-December 31, 2011				
Assets:				
Commodity derivative instruments	$	$	$ 43,079	$ 43,079
Liabilities:				
Commodity derivative instruments			186	186
Predecessor-December 31, 2010				
Assets:				
Commodity derivative instruments	$	$	$ 31,586	$ 31,586
Liabilities:				
Commodity derivative instruments			7,221	7,221
Interest rate derivative instruments			861	861

On November 16, 2011, the predecessor novated certain of its derivative instruments to us. These derivative instruments were accounted for at fair value on a nonrecurring basis of a $36.2 million net asset position (Note 1). These derivative instruments are classified as Level 3 fair value measurements.

All fair values reflected in the table above and on the combined balance sheets have been adjusted for non-performance risk. The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Commodity Derivative Instruments The fair value of the commodity derivative instruments is estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services reflecting broker market quotes.

Interest Rate Derivative Instruments The fair value of the interest rate derivative instruments is estimated using a combined income and market valuation methodology based upon forward interest rates and volatility curves. The curves are obtained from independent pricing services reflecting broker market quotes. We did not have any outstanding interest rate derivative instruments at December 31, 2011.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the periods indicated (in thousands):

	Partnership	Predecessor		
	November 16 to December 31, 2011	January 1 to November 15, 2011	Year Ended December 31, 2010	2009
Balance at beginning of period	$ 36,229	$ 23,504	$ 47,716	$ 109,996
Total gains or losses (realized or unrealized):				
Included in earnings	10,679	21,894	23,168	8,165
Settlements	(4,015)	(8,779)	(47,380)	(70,445)
Transfers in and out of Level 3				
Balance at end of period	$ 42,893	$ 36,619	$ 23,504	$ 47,716
	$ 6,664	$ 13,115	$ (24,212)	$ (62,280)

Changes in unrealized gains (losses) relating to derivatives still held at end of period

5. Property and Equipment

Property and equipment is stated at cost less accumulated depletion, depreciation and impairment and consisted of the following (in thousands):

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		Partnership December 31, 2011		Predecessor December 31, 2010
Oil and natural gas properties (successful efforts method)	$	642,519	$	781,495
Unproved properties		1,367		2,133
Other property and equipment		302		718
		644,188		784,346
Accumulated depletion, depreciation and impairment		(245,581)		(342,400)
Total property and equipment, net	$	398,607	$	441,946

We recorded $3.9 million of depletion and depreciation expense for the period from November 16 to December 31, 2011. The predecessor recorded $37.2 million, $55.8 million and $56.3 million of depletion and depreciation expense for the period from January 1 to November 15, 2011 and the years ended December 31, 2010 and 2009, respectively.

For the year to date period ending November 15, 2011 and the year ended December 31, 2010, due to a significant decline in future natural gas price curves across all future production periods, we performed an impairment analysis of our oil and natural gas properties and other non-current assets. For the year to date period ending November 15, 2011, we recorded a total non-cash impairment charge of approximately $16.8 million to impair the value of our proved oil and natural gas properties in the Mid-Continent region. For the year ended December 31, 2010, we recorded a total non-cash impairment charge of approximately $11.7 million, composed of $10.9 million and $0.8 million to impair the value of our proved and unproved oil and natural gas properties in the Gulf Coast, respectively. Our unproved properties were impaired based on the drilling locations for the probable and possible reserves becoming uneconomic at the lower future expected natural gas prices and our future expected drilling schedules. These non-cash charges are included in Impairment of oil and natural gas properties line item in the predecessor s combined statements of operations. We did not record any impairment charges in the period from November 16 to December 31, 2011 or the year ended December 31, 2009.

These impairments of proved and unproved oil and natural gas properties were recorded because the net capitalized costs of the properties exceeded the fair value of the properties as measured by estimated cash flows reported in a third party reserve report. This report was based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are Level 3 inputs. 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 the predecessor s estimated cash flows are the product of a process that begins with New York Mercantile Exchange (NYMEX) forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Furthermore, significant assumptions in valuing the proved reserves included the reserve quantities, anticipated drilling and operating costs, anticipated production taxes, future expected natural gas prices and basis differentials, anticipated drilling schedules, anticipated production declines, and an appropriate discount rate commensurate with the risk of the underlying cash flow estimates. Cash flow estimates for the impairment testing excluded derivative instruments used to mitigate the risk of lower future natural gas prices. Significant assumptions in valuing the unproved reserves included the evaluation of the probable and possible reserves included in the third party reserve report, future expected natural gas prices and basis differentials, and the Predecessor s anticipated drilling schedules.

These asset impairments have no impact on the predecessor s cash flows, liquidity position, or debt covenants. If expected future oil and natural gas prices continue to decline during 2012, the estimated undiscounted future 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.

6. Asset Retirement Obligations

The following is a summary of our ARO as of and for the periods indicated (in thousands):

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	November 16, 2011 to December 31, 2011	For the Year to Date Period Ending November 15, 2011	For the Year Ended December 31, 2010
Beginning of period	$ 22,673	$ 24,296	$ 19,194
Assumed in acquisitions		202	2,994
Divested properties			(526)
Revisions to previous estimates			1,212
Liabilities incurred	298		550
Liabilities settled		(443)	(494)
Accretion expense	168	1,290	1,366
End of period	23,139	25,345	24,296
Less: Current portion of ARO	359	359	792
Asset retirement obligation- non-current	$ 22,780	$ 24,986	$ 23,504

7. Long-Term Debt

In July 2011, subject to consummation of our IPO, we, as guarantor, and our wholly owned subsidiary, OLLC, as borrower, entered into a five-year, $500 million senior secured revolving credit facility (the Credit Agreement) that matures in July 2016. The Credit Agreement is reserve-based and we are permitted to borrow under our credit facility in an amount up to the borrowing base, which is currently $250 million. Our borrowing base, which is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts, is subject to redetermination semi-annually by our lenders at their sole discretion. Unanimous approval by the lenders is required for any increase to the borrowing base.

Borrowings under the Credit Agreement are secured by liens on at least 80% of the PV-10 value of our and our subsidiaries oil and natural gas properties and all of our equity interests in the OLLC and any future guarantor subsidiaries and all of our and our subsidiaries other assets including personal property. 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 0.75% to 1.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letter of credit exposure to the borrowing base then in effect), or (ii) the applicable reserve-adjusted LIBOR plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

The Credit Agreement requires us to maintain a leverage ratio of Total Debt to EBITDAX (as each term is defined in the Credit Agreement) of not more than 4.0 to 1.0, and a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0.

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. We were in compliance with our covenants as of December 31, 2011.

As of December 31, 2011, we had approximately $155.8 million of outstanding debt and accrued interest was approximately $0.5 million. Interest expense for the period from November 16 to December 31, 2011 was approximately $0.6 million. As of December 31, 2011, the interest rate on our Credit Agreement was an average of 2.86%.

As of December 31, 2010, LRR A had a $45 million credit facility and its availability under the credit facility was restricted to the borrowing base of $31.5 million. The borrowing base is subject to review and adjustment on a semiannual basis and other interim adjustments as requested by the lenders or LRR A, as applicable. At the election of LRR A, amounts outstanding under the credit facility bear interest at specified margins over the LIBOR of 2.00%

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to 2.75% or specified margins over the Alternate Base Rate 1.00% to 1.75%. The Alternate Base Rate is the greatest of the Prime Rate, the Fed Funds Rate plus 1/2 of 1%, or the adjusted LIBOR for a one-month Interest Period plus 1%. Such margins will fluctuate based on the utilization of the facility. As of December 31, 2010, the interest rate on LRR A s revolving line of credit, taking into account the Predecessor s interest rate swaps, was an average of 5.26%.

Borrowings under the credit facility are collateralized by a perfected, first-priority security interest in substantially all of the oil and natural gas properties owned by LRR A. LRR A is subject to financial covenants with respect to current ratio, interest coverage ratio, and ratio of debt to EBITDAX. EBITDAX is defined as net income plus interest, income taxes, depreciation, depletion, amortization, exploration expenses, and other noncash charges, and minus all noncash income. If a material acquisition (as defined in the credit facility) is made during the quarter, the credit facility provides that the EBITDAX be calculated giving pro forma effect as if such acquisition occurred on the first day of such quarter. In addition, LRR A is subject to covenants limiting restricted payments, transactions with affiliates, incurrence of debt, asset sales, and liens on properties. LRR A was in compliance with all of the financial covenants as of December 31, 2010, with the exception of the current ratio. LRR A obtained a waiver for the current ratio requirement at December 31, 2010.

All amounts drawn under the credit facility are due and payable on November 23, 2014. At December 31, 2010, borrowings under the credit facility were $27.3 million and accrued interest payable was $0.1 million.

8. Derivatives

Objective and strategy We are exposed to commodity price and interest rate risk and consider it prudent to periodically reduce our exposure to cash flow variability resulting from commodity price changes and interest rate fluctuations. Accordingly, we enter into derivative instruments to manage our exposure to commodity price fluctuations, locational differences between a published index and the NYMEX futures on natural gas or crude oil productions, and interest rate fluctuations.

At December 31, 2011 and 2010, our open positions consisted of contracts such as (i) crude oil and natural gas financial collar contracts, (ii) crude oil, NGL and natural gas financial swaps, (iii) natural gas basis financial swaps and (iv) interest rate swap agreements. Our derivative instruments are with the counterparties that are also lenders in our credit facility.

Swaps and options are used to manage our exposure to commodity price risk and basis risk inherent in our oil and natural gas production. Commodity price swap agreements are used to fix the price of expected future oil and natural gas sales at major industry trading locations such as Henry Hub Louisiana (HH) for gas and Cushing Oklahoma (WTI) for oil. Basis swaps are used to fix the price differential between the product price at one location versus another. Options are used to establish a floor and a ceiling price (collar) for expected oil or gas sales. Interest rate swaps are used to fix interest rates on existing indebtedness.

Under commodity swap agreements, we exchange a stream of payments over time according to specified terms with another counterparty. Specifically for commodity price swap agreements, we agree to pay an adjustable or floating price tied to an agreed upon index for the commodity, either gas or oil, and in return receives a fixed price based on notional quantities. Under basis swap agreements, we agree to pay an adjustable or floating price tied to two agreed upon indices for gas and in return receive the differential between a floating index and fixed price based on notional quantities. A collar is a combination of a put purchased by us and a call option written by us. In a typical collar transaction, if the floating price based on a market index is below the floor price, we receive from the counterparty an amount equal to this difference multiplied by the specified volume, effectively a put option. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, we must pay the counterparty an amount equal to the difference multiplied by the specific quantity, effectively a call option.

The interest rate swap agreements effectively fix our interest rate on amounts borrowed under the credit facility. The purpose of these instruments is to mitigate our existing exposure to unfavorable interest rate changes. Under interest rate swap agreements, we pay a fixed interest rate payment on a notional amount in exchange for receiving a floating amount based on LIBOR on the same notional amount.

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We elected not to designate any positions as cash flow hedges for accounting purposes and, accordingly, recorded the net change in the mark-to-market valuation of these derivative contracts in the statements of operations. We record our derivative activities on a mark-to-market or fair value basis. Fair values are based on pricing models that consider the time value of money and volatility and are comparable to values obtained from counterparties. Pursuant to the accounting standard that permits netting of assets, liabilities, and collateral where the right of offset exists, we present the fair value of derivative financial instruments on a net basis.

At December 31, 2011, we had the following open commodity derivative contracts:

	Index	2012	2013	2014	2015
Natural gas positions					
Price swaps (MMBTUs)	NYMEX-HH	3,684,189	5,757,645	5,107,055	4,596,205
Weighted average price		$ 6.21	$ 5.59	$ 5.76	$ 5.96
Collars (MMBTUs)	NYMEX-HH	2,902,801			
Floor-Ceiling price		$ 4.75-7.31	$	$	$
Oil Positions					
Price swaps (BBLs)	NYMEX-WTI	251,005	289,323	248,149	219,657
Weighted average price		$ 102.20	$ 101.30	$ 100.01	$ 98.90
NGL Positions					
Price swaps (BBLs)	Mont Belvieu	164,220			
Weighted average price		$ 49.92	$	$	$

At December 31, 2010, the predecessor had the following commodity derivative open positions:

	Index	2011	2012	2013	2014
Natural gas positions					
Price swaps (MMBTUs)	NYMEX-HH	7,837,761	3,684,189	2,904,560	902,048
Weighted average price		$ 6.73	$ 6.21	$ 5.86	$ 6.60
Basis swaps (MMBTUs)	NYMEX-HH	8,016,800	6,884,480	6,077,280	
Weighted average price		$ (0.25)	$ (0.30)	$ (0.31)	
Collars (MMBTUs)	NYMEX-HH		3,375,741		
Floor-Ceiling price			$ 4.64-7.16		
Oil Positions					
Price swaps (BBLs)	NYMEX-WTI	325,684	267,680	256,176	220,944
Weighted average price		$ 103.49	$ 85.76	$ 86.77	$ 87.44
Collars (BBLs)	NYMEX-WTI	81,600			
Floor-Ceiling price		$ 120.00-171.50			

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At December 31, 2010, the predecessor had the following interest rate swap contracts:

Maturity	Notional Amount (in thousands)		Average %	Index
May 2011	$	2,130	3.590%	LIBOR
February 2012		5,351	1.180	LIBOR
November 2012		9,500	3.300	LIBOR
February 2013		5,135	2.205	LIBOR
February 2013		5,135	2.260	LIBOR

Effect of Derivative Instruments Balance Sheets

The fair value of our commodity and interest rate derivative instruments as of December 31, 2011 is included in the table below (in thousands):

	As of December 31, 2011							
	Current Assets		Long-term Assets		Current Liabilities		Long-term Liabilities	
Sale of Natural Gas Production								
Price swaps	$	10,762	$	22,190	$		$	
Collars		4,464						
Sale of Crude Oil Production								
Price swaps		838		4,825				
Sale of NGLs								
Price swaps						186		
	$	16,064	$	27,015	$	186	$	

The fair value of our predecessor s commodity and interest rate derivative instruments as of December 31, 2010 is included in the table below (in thousands):

	As of December 31, 2010							
	Current Assets		Long-term Assets		Current Liabilities		Long-term Liabilities	
Interest rate								
Swaps	$		$		$	594	$	267
Sale of Natural Gas Production								
Price swaps		16,929		6,590				
Basis swaps						379		621
Collars				1,177				161
Sale of Crude Oil Production								
Price swaps		4,694				1,509		4,551
Collars		2,196						
	$	23,819	$	7,767	$	2,482	$	5,600

Effect of Derivative Instruments Statements of Operations

The unrealized gain or loss amounts and classification related to derivative instruments for the periods indicated are as follows (in thousands):

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	Partnership November 16 to December 31, 2011	January 1 to November 15, 2011	Predecessor Year Ended December 31, 2010	2009
Realized gains (losses):				
Commodity derivatives (revenue)	$ 4,015	$ 9,353	$ 48,029	$ 70,902
Interest rate derivatives (other income/expense)		(574)	(649)	(457)
Unrealized gains (losses):				
Commodity derivatives (revenue)	6,664	12,674	(23,964)	(62,375)
Interest rate derivatives (other income/expense)		441	(248)	95

Credit Risk. All of our derivative transactions have been carried out in the over-the-counter market. The use of derivative instruments involves the risk that the counterparties may be unable to meet the financial terms of the transactions. We monitor the creditworthiness of each of its counterparties and assess the possibility of whether each counterparty to the derivative contract would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. We also have netting arrangements in place with each counterparty to reduce credit exposure. The derivative transactions are placed with major financial institutions that present minimal credit risks to us. Additionally, we consider ourselves to be of substantial credit quality and have the financial resources and willingness to meet our potential repayment obligations associated with the derivative transactions.

9. Related Parties

Ownership in Our General Partner by the Management of Fund I and its Affiliates

As of December 31, 2011, Lime Rock Management, an affiliate of Fund I owned 100% of our general partner and Fund I owned an aggregate of approximately 32.2% of our outstanding common units and all of our subordinated units representing limited partner interests in us. In addition, our general partner owned an approximate 0.1% general partner interest in us, represented by 22,400 general partner units, and all of our incentive distribution rights.

Contracts with our General Partner and its Affiliates

We have entered into agreements with our general partner and its affiliates. Refer to Note 1 for a description of those agreements. For the period from November 16 to December 31, 2011, we paid Lime Rock Management approximately $0.6 million, either directly or indirectly related to these agreements.

Distributions of Available Cash to Our General Partner and Affiliates

We will generally make cash distributions to our unitholders and our general partner pro rata. As of December 31, 2011, our general partner and its affiliates held 5,049,600 of our common units, all of our subordinated units and 22,400 general partner units. No cash distributions were made from November 16 to December 31, 2011. The Partnership made a cash distribution on February 14, 2012 as discussed in Note 14.

Predecessor Related Parties

Each of LRR A, LRR B and LRR C has a management agreement with Lime Rock Management, an affiliated entity, to provide management services for the operation and supervision of their respective funds. The management fee is determined by a formula based on the partners invested capital or the equity capital commitment. During the period from January 1 to November 15, 2011, the predecessor expensed $5.4 million in management fees to Lime Rock Management. The predecessor expensed $6.1 million and $8.5 million related to management fees to Lime Rock Management for the years ended December 31, 2010 and 2009, respectively.

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In the normal course of business, certain expenses of the predecessor may be paid by, and subsequently reimbursed to, Lime Rock Management. There were no outstanding amounts due to Lime Rock Management at December 31, 2010.

In addition, through the normal course of business, certain expenses of the predecessor may be paid by, and subsequently reimbursed to, OpCo, an affiliated entity, pursuant to a services agreement. As of December 31, 2010, the predecessor had a minimal amount due to or from OpCo.

For certain oil and natural gas properties where the predecessor is the operator, the predecessor receives income related to joint interest operations. For the period from January 1 to November 15, 2011, the predecessor received $0.9 million, of income, which reduced the management fee paid by the predecessor to Lime Rock Management. The predecessor did not record any such amounts during the years ended December 31, 2010 and 2009. All related party transactions are at amounts believed to be commensurate with an arm s-length transaction between parties and are stated at fair market value.

10. Unitholders Equity

Initial Public Offering

On November 16, 2011, we completed our IPO of 9,408,000 common units representing limited partner interests in the Partnership at a price to the public of $19.00 per common unit, or $17.8125 per common unit after payment of the underwriting discount. Total net proceeds from the sale of common units in our IPO were $167.2 million ($178.8 million less $11.2 million for the underwriting discount and a $0.4 million structuring fee). IPO costs were approximately $4.7 million. We reimbursed Fund I for all costs they paid related to our IPO ($3.2 million). Net proceeds of the offering, along with $155.8 million of borrowings under our new $500 million senior secured revolving credit agreement were utilized to make cash distributions and payments to Fund I of approximately $289.9 million and repay $27.3 million of LRR A s debt that we assumed at closing.

On December 14, 2011, we closed the partial exercise of the underwriters option to purchase additional units and as a result issued an additional 1,200,000 common units to the public. We used the net proceeds from the sale of the additional common units of $21.3 million, after deducting underwriting discounts and a structuring fee, to pay additional cash consideration for the properties purchased from Fund I in connection with the IPO and to make additional distributions to Fund I. In connection with our IPO, Fund I received total consideration for the Partnership Properties of 5,049,600 common units, 6,720,000 subordinated units, $311.2 million in cash and the assumption of $27.3 million of LRR A s indebtedness.

Units Outstanding

As of December 31, 2011, we had 15,700,074 common units, 6,720,000 subordinated units and 22,400 general partner units outstanding. In addition, as of December 31, 2011, Fund I owned 5,049,600 common units and all of our subordinated units, representing a 52.4% limited partner interest in us.

Common Units

The common units have limited voting rights as set forth in our partnership agreement.

Subordinated Units

The principal difference between our common units and subordinated units is that in any quarter during the subordination period, the subordinated units are entitled to receive the minimum quarterly distribution only after the common units have received their minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Accordingly, holders of subordinated units may receive a smaller distribution than holders of common units or no distribution at all. Subordinated units will not accrue arrearages.

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The subordination period will extend until the first business day of any quarter after December 31, 2014 that we have 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, provided there are no arrearages in the minimum quarterly distribution on our common units at that time. However, three separate one third tranches of subordinated units may 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, has been earned and paid prior to the applicable date, in each case provided there are no arrearages in the minimum quarterly distribution on our common units at that time.

In addition, the subordination period will end on the first business day after we have earned and paid from operating surplus at least (i) $0.54625 per quarter (115% of the minimum quarterly distribution, which is $2.185 on an annualized basis) on each outstanding common and subordinated unit and the corresponding distributions on our general partner s approximate 0.1% interest and the incentive distribution rights for any four quarter period ending on or after December 31, 2013, or (ii) $0.59375 per quarter (125% of the minimum quarterly distribution, which is $2.375 on an annualized basis) on each outstanding common and subordinated unit and the corresponding distributions on our general partner s approximate 0.1% interest and the incentive distribution rights for any four quarter period, in each case provided there are no arrearages in the minimum quarterly distribution on our common units at that time.

The subordination period will also end upon the removal of our general partner other than for cause if the units held by our general partner and its affiliates are not voted in favor of such removal. When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and all common units thereafter will no longer be entitled to arrearages.

General Partner Interest

Our general partner owns an approximate 0.1% interest in us. This interest entitles our general partner to receive distributions of available cash from operating surplus as discussed further below under Cash Distributions. Our partnership agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the common unitholders, subordinated unitholders and our general partner will receive.

Our general partner has sole responsibility for conducting our business and managing our operations. Our general partner s board of directors and executive officers will make decisions on our behalf.

Allocation of Net Income

Net income is allocated between our general partner and the common and subordinated unitholders in proportion to their pro rata ownership during the period.

Cash Distributions

Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ending December 31, 2011, 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;

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

- provide funds for distributions to our unitholders (including our general partner) for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for future distributions on our subordinated units 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.

Upon the closing of our initial public offering, Fund I received an aggregate of 6,720,000 subordinated units. During the subordination period, the common units will have 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 may be made on the subordinated units. These units are deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions from operating surplus until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash from operating surplus to be distributed on the common units.

The subordination period will extend until the first business day of any quarter after December 31, 2014 that we have 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, provided there are no arrearages in the minimum quarterly distribution on our common units at that time. However, three separate one third tranches of subordinated units may 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, has been earned and paid prior to the applicable date, in each case provided there are no arrearages in the minimum quarterly distribution on our common units at that time.

In addition, the subordination period will end on the first business day after we have earned and paid from operating surplus at least (i) $0.54625 per quarter (115% of the minimum quarterly distribution, which is $2.185 on an annualized basis) on each outstanding common and subordinated unit and the corresponding distributions on our general partner s 0.1% interest and the incentive distribution rights for any four quarter period ending on or after December 31, 2013, or (ii) $0.59375 per quarter (125% of the minimum quarterly distribution, which is $2.375 on an annualized basis) on each outstanding common and subordinated unit and the corresponding distributions on our general partner s 0.1% interest and the incentive distribution rights for any four quarter period, in each case provided there are no arrearages in the minimum quarterly distribution on our common units at that time.

The subordination period will also end, with respect to subordinated Units held by any person, upon the removal of our general partner other than for cause if the units held by such person and its affiliates are not voted in favor of such removal and such person is not an affiliate of the successor to the general partner.

When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and all common units thereafter will no longer be entitled to arrearages.

During Subordination Period. Assuming our general partner maintains its 0.1% general partner interest in us, our partnership agreement requires us to distribute all of our available cash from operating surplus for each quarter in the following manner during the subordination period:

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- 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 the common unitholders, pro rata, and 0.1% to our general partner, until we distribute 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 distribute 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 receives a total of $0.54625 per unit for that quarter.

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

Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions: Unitholders	Marginal Percentage Interest in Distributions: 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 its approximate 0.1% general partner interest. We refer to the additional increasing distributions to our general partner in excess of its approximate 0.1% 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.

- *thereafter*, as provided in the table above.

11. Net Income Per Limited Partner Unit

The following sets forth the calculation of net income per limited partner unit for the period from November 16 to December 31, 2011 (in thousands, except per unit amounts):

Net income	$	12,150
Less: General partner s 0.1% interest in net income		(12)
Limited partners interest in net income	$	12,138
Weighted average limited partner units outstanding:		
Common units		15,698
Subordinated units		6,720
Total		22,418
Net income per limited partner unit (basic and diluted)	$	0.54

Our subordinated units and restricted unit awards are considered to be participating securities for purposes of calculating our net income per limited partner unit, and accordingly, are included in basic computation as such. Net income per limited partner unit is determined by dividing the net income available to the common unitholders, after deducting our general partner s approximate 0.1% interest in net income, by the number of common units and subordinated units outstanding as of December 31, 2011. The aggregate number of common units and subordinated units was 15,700,074 and 6,720,000. The majority of the units were outstanding since November 16, 2011.

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12. Equity-Based Compensation

On November 10, 2011, our General Partner adopted a long-term incentive plan (2011 LTIP) for employees, consultants and directors of our General Partner and its affiliates, including Lime Rock Management and OpCo, who perform services for us. The 2011 LTIP consists of unit options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, unit awards and other unit-based awards. The 2011 LTIP initially limits the number of units that may be delivered pursuant to vested awards to 1,500,000 common units. As of December 31, 2011, there were 1,457,526 units available for issuance under the 2011 LTIP. The 2011 LTIP will be administered by our General Partner s board of directors or a committee thereof.

The fair value of restricted units is determined based on the fair market value of the units on the date of grant. The outstanding restricted units vest over three years in equal amounts (subject to rounding) on the date of grant and are entitled to receive quarterly distributions during the vesting period.

A summary of the status of the non-vested units as of December 31, 2011, is presented below:

	Number of Non-vested Units	Weighted Average Grant-Date Fair Value
Non-vested restricted units at November 16, 2011		$
Granted	42,474	18.88
Vested		
Forfeited		
Non-vested units at December 31, 2011	42,474	

As of December 31, 2011, there was approximately $0.8 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 2.9 years. There were no vested restricted units as of December 31, 2011.

13. Contractual Obligations and Commitments

In the normal course of business, we enter into contracts that contain a variety of representations and warranties and provide general indemnifications. Our maximum exposure under these arrangements is unknown as this would involve future claims that may be made against us that have not yet occurred. We do not expect to suffer any material losses in connection with these contracts.

Various federal, state and local laws and regulations covering, among other things, the release of waste materials into the environment and state and local taxes affect our operations and costs. Our management believes we are in substantial compliance with applicable federal, state and local laws, and management expects that the ultimate resolution of any claims or legal proceedings instituted against us will not have a material effect on our financial position or results of operations.

14. Subsequent Events

Unit Distribution

On February 14, 2012, we paid a pro-rated cash distribution of $0.2323 per outstanding unit. The pro-rated amount corresponded to our minimum quarterly cash distribution of $0.4750 per unit, or $1.90 on an annualized basis. The proration period began on November 17, 2011, the day after the closing date of LRR Energy s initial public offering, and ended December 31, 2011. The aggregate amount of the distribution was $5.2 million.

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Derivative Instruments

In January 2012, we entered into the following oil and NGL price swaps.

	Index	2012	2013
Oil Hedges			
Price swaps (Bbls)	NYMEX-WTI	133,925	
Weighted average price		$ 102.90	$
NGL Hedges			
Price swaps (Bbls)	Mont Belvieu	8,543	123,750
Weighted average price		$ 95.61	$ 51.31

In February 2012, we entered into the following natural gas basis swaps. These contracts are designed to effectively fix a price differential between 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**
2012	$ (0.160)	6,345	$ (0.065)	3,581	$ (0.090)	4,198	$ (0.080)	916
2013	$ (0.195)	6,756	$ (0.090)	3,399	$ (0.120)	4,667	$ (0.105)	953
2014	$ (0.215)	6,086	$ (0.085)	2,859	$ (0.130)	4,193	$ (0.125)	854
2015	$ (0.230)	5,525	$ (0.100)	2,476	$ (0.140)	3,815	$ (0.138)	776

Also in February 2012, we entered into three interest rate swaps to effectively fix our interest rate on $150.0 million of the amount borrowed under our credit facility. The first instrument has a fixed rate of 0.5175% per month and expires in February 2015. The other two instruments are effective in February 2015 for an average fixed rate of 1.72625% per month and expires in February 2017.

15. Supplemental Information on Oil and Natural Gas Exploration and Production Activities (Unaudited)

Oil and Natural Gas Capitalized Costs

Capitalized costs relating to oil and natural gas producing activities are as follows at December 31 (in thousands):

	Partnership 2011	Predecessor 2010

Proved oil and natural gas properties	$	642,519	$	781,495
Unproved oil and natural gas properties		1,367		2,133
		643,886		783,628
Accumulated depletion and depreciation		(245,565)		(342,042)
Net capitalized costs	$	398,321		441,586

Costs Incurred in Oil and Natural Gas Property Acquisition and Development Activities

Costs incurred in oil and natural gas property acquisition and development activities are as follows (in thousands):

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	Partnership November 16 to December 31, 2011	Predecessor January 1 to November 15, 2011	Year ended December 31, 2010	2009
Acquisition of oil and natural gas properties				
Proved	$ 56	$ 392	$ 105,209	$ 8,514
Unproved				
Development costs	2,461	48,702	44,680	26,072
Total	$ 2,517	49,094	$ 149,889	$ 34,586

We had immaterial exploration costs for each of the periods during 2011, 2010 and 2009.

Oil and Natural Gas Reserves

The reserve disclosures that follow reflect estimates of proved reserves, proved developed reserves and proved undeveloped reserves, net of third-party royalty interests, of natural gas, crude oil and condensate, and NGLs owned at each year end and changes in proved reserves during each of those periods. Natural gas volumes are in millions of cubic feet (MMcf) at a pressure base of 14.73 pounds per square inch and volumes for oil, condensate and NGLs are in thousands of barrels (MBbls). Total volumes are presented in thousands of barrels of oil equivalent (MBOE). For this computation, one barrel of oil is assumed to be the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural gas reserve volumes.

Our estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions and governmental restrictions, as well as changes in the expected recovery associated with infill drilling.

Our oil and natural gas properties and associated reserves are located in the continental United States. The following table presents the estimated remaining net proved, proved developed and proved undeveloped oil and natural gas reserves as of the periods indicated, and the related summary of changes in estimated quantities of net remaining proved reserves during those periods. Our estimated reserves at December 31, 2011 and 2010 were based on reserve reports prepared by the independent reserve engineers Miller and Lents, Ltd. and Netherland, Sewell & Associates, Inc. Our predecessor s estimated reserves at December 31, 2009 were based on evaluations prepared by our predecessor s internal petroleum engineers and staff.

	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)
Partnership:			
Balance, November 16, 2011			
Contribution from predecessor	7,360	3,092	111,981
Production	(65)	(27)	(1,038)
Balance, December 31, 2011	7,295	3,065	110,943

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	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)
Predecessor:			
Balance, December 31, 2008	5,797	1,471	80,594
Revision of previous estimates	(168)	1,103	(13,178)
Extensions and discoveries	562	303	2,374
Acquisition of minerals in place	16	66	2,629
Sales of minerals in place	(7)		(685)
Production	(602)	(363)	(9,076)
Balance, December 31, 2009	5,598	2,580	62,658
Revision of previous estimates	92	315	6,681
Extensions and discoveries	927	438	2,583
Acquisition of minerals in place	40	97	49,560
Sales of minerals in place	(22)	(9)	(594)
Production	(698)	(376)	(11,287)
Balance, December 31, 2010	5,937	3,045	109,601
Revision of previous estimates	126	(196)	10,359
Extensions and discoveries	3,902	1,094	7,243
Acquisition of minerals in place			
Sales of minerals in place	(29)		(75)
Production	(657)	(269)	(8,606)
Balance, November 15, 2011	9,279	3,674	118,522

	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)
Proved developed reserves:			
December 31, 2009 (predecessor)	4,398	2,191	60,668
December 31, 2010 (predecessor)	4,970	2,605	105,465
December 31, 2011 (partnership)	5,275	2,334	101,813
Proved undeveloped reserves:			
December 31, 2009 (predecessor)	1,199	389	1,990
December 31, 2010 (predecessor)	967	440	4,136
December 31, 2011 (partnership)	2,020	731	9,130

Standardized Measure of Discounted Future Net Cash Flows

Oil and natural gas reserve estimation and disclosure regulations require that reserve estimates and discounted future net cash flows are based on the unweighted average market prices for sales of oil and natural gas on the first calendar day of each month during the year. Cash flows are adjusted for transportation fees and regional price differentials, to the estimated future production of proved oil and natural gas reserves less estimated future expenditures to be incurred in developing and producing the proved reserves, discounted using an annual rate of 10% to reflect the estimated timing of the future cash flows. Income taxes are excluded because we and the Predecessor are non-taxable entities. Generally, all taxable income and losses are reported on the income tax returns of the unitholders and partners, and therefore, no provision for income taxes has been recorded in the accompanying combined financial statements. Extensive judgments are involved in estimating the timing of production and the costs that will be incurred throughout the remaining lives of the properties. Accordingly, the estimates of future net cash flows from proved reserves and the present value may be materially different from subsequent actual results. The standardized measure of discounted net cash flows does not purport to present, nor should it be interpreted to present, the fair value of the acquired properties   oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, and anticipated future changes in prices and costs.

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The standardized measure of discounted future net cash flows related to our interest in proved reserves as of the periods indicated are as follows (in thousands):

	Partnership November 16 to December 31, 2011	January 1 to November 15, 2011	Predecessor Year ended December 31, 2010	2009
Future cash inflows	$ 1,275,917	$ 1,497,384	$ 1,039,219	$ 582,581
Future costs:				
Development	(140,987)	(157,048)	(40,659)	(27,868)
Production	(394,265)	(467,401)	(354,350)	(211,355)
Future net cash flows	740,665	872,935	644,210	343,358
10% discount to reflect timing of cash flows	(398,331)	(454,253)	(295,812)	(150,410)
Standardized measure of discounted future net cash flows	$ 342,334	$ 418,682	$ 348,398	$ 192,948

The principal changes in the standardized measure of discounted future net cash flows attributable to our proved reserves as of the periods indicated are as follows (in thousands):

	Partnership November 16 to December 31, 2011	January 1 to November 15, 2011	Predecessor Year ended December 31, 2010	2009
Beginning of period	$	$ 348,398	$ 192,948	$ 246,567
Contribution from predecessor	350,210			
Purchase of reserves in place			76,007	5,055
Sales of reserves in place		(676)	(535)	(1,605)
Extensions and discoveries, net of future development costs		120,120	46,947	18,675
Revisions of quantity estimates		17,326	23,467	(14,322)
Changes in future development costs, net		1,125	(5,148)	4,122
Development costs incurred that reduce future development costs		4,331	4,013	1,210
Net changes in prices		15,374	77,696	(26,137)
Oil, natural gas and NGL sales, net of production costs	(7,876)	(96,585)	(82,382)	(53,222)
Changes in timing and other		(25,571)	(3,910)	(12,052)
Accretion of discount		34,840	19,295	24,657
End of period	$ 342,334	$ 418,682	$ 348,398	$ 192,948

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16. Selected Quarterly Financial Information (Unaudited)

Quarterly financial data was as follows for the periods indicated (in thousands):

	Predecessor				Partnership
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter (1)	Fourth Quarter (1)
2011					
Revenues	$ 18,650	$ 42,535	$ 66,208	$ 4,781	$ 21,846
Operating income (loss)	(5,856)	24,298	25,578	(7,341)	12,802
Net income (loss)	(6,210)	23,813	25,582	(7,481)	12,150
Net income per limited partner unit	n/a	n/a	n/a	n/a	$ 0.54
2010					
Revenues	$ 46,425	$ 37,511	$ 36,635	$ 19,116	$ n/a
Operating income (loss)	9,159	10,595	11,258	(4,543)	n/a
Net income (loss)	8,512	9,922	10,639	(6,739)	n/a
Net income per limited partner unit	n/a	n/a	n/a	n/a	n/a

(1) Fourth quarter 2011 results are split 46 days each under predecessor and partnership to reflect the closing of the IPO.