LEGACY RESERVES LP
Form 10-K
February 21, 2014

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

Form 10-K

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

For the fiscal year ended December 31, 2013

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 1-33249

Legacy Reserves LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	16-1751069 (I.R.S. Employer Identification No.)
303 W. Wall Street, Suite 1800 Midland, Texas (Address of principal executive offices)	79701 (Zip Code)

Registrant's telephone number, including area code:
(432) 689-5200

Securities registered pursuant to Section 12(b) of the Act:
Units representing limited partner interests listed on the NASDAQ Stock Market LLC.

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 þ No o

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 þ

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 þ 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 þ 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. þ

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 þ Accelerated filer o Non-accelerated filer o Smaller reporting company o
(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 þ

The aggregate market value of units held by non-affiliates of the registrant was approximately $1,258.0 million on June 30, 2013, based on $26.60 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

57,514,735 units representing limited partner interests in the registrant were outstanding as of February 20, 2014.

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrant’s 2014 annual meeting of unitholders are incorporated by reference into Part III of this annual report on Form 10-K.

LEGACY RESERVES LP

Table of Contents

GLOSSARY OF TERMS

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Boe. One barrel of oil equivalent determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development project. A drilling or other project which may target proven reserves, but which generally has a lower risk than that associated with exploration projects.

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.

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

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Hydrocarbons. Oil, NGLs and natural gas are all collectively considered hydrocarbons.

Liquids. Oil and NGLs.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet.

MGal. One thousand gallons of natural gas liquids or other liquid hydrocarbons.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

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

NYMEX. New York Mercantile Exchange.

Oil. Crude oil and condensate.

Table of Contents

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved developed non-producing or PDNPs. Proved oil and natural gas reserves that are developed behind pipe or shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

Proved reserves. Proved oil and natural gas reserves are 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.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves or PUDs. Proved oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reserve acquisition cost. The total consideration paid for an oil and natural gas property or set of properties, which includes the cash purchase price and any value ascribed to units issued to a seller adjusted for any post-closing items.

R/P ratio (reserve life). The reserves as of the end of a period divided by the production volumes for the same period.

Reserve replacement. The replacement of oil and natural gas produced with reserve additions from acquisitions, reserve additions and reserve revisions.

Reserve replacement cost. An amount per Boe equal to the sum of costs incurred relating to oil and natural gas property acquisition, exploitation, development and exploration activities (as reflected in our year-end financial statements for the relevant year) divided by the sum of all additions and revisions to estimated proved reserves, including reserve purchases. The calculation of reserve additions for each year is based upon the reserve report of our independent engineers. Management uses reserve replacement cost to compare our company to others in terms of our historical ability to increase our reserve base in an economic manner. However, past performance does not necessarily reflect future reserve replacement cost performance. For example, increases in oil and natural

Table of Contents

gas prices in recent years have increased the economic life of reserves, adding additional reserves with no required capital expenditures. On the other hand, increases in oil and natural gas prices have increased the cost of reserve purchases and reserves added through development projects. The reserve replacement cost may not be indicative of the economic value of the reserves added due to differing lease operating expenses per barrel, differing timing of production, and other qualitative factors.

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.

Standardized measure. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price for each month) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on its share of Legacy's taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure. Standardized measure does not give effect to commodity 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.

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

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

Table of Contents

CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING INFORMATION

This document 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 strategy;
- the amount of oil and natural gas we produce;
- the price at which we are able to sell our oil and natural gas production;
- our ability to acquire additional oil and natural gas properties at economically attractive prices;
- our drilling locations and our ability to continue our development activities at economically attractive costs;
- the level of our lease operating expenses, general and administrative costs and finding and development costs, including payments to our general partner;
- the level of our capital expenditures;
- the level of cash distributions to our unitholders;
- our future operating results; and
- our plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this document, are forward-looking statements. In some cases, you can identify forward-looking statements by terminology such as “may,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “continue,” such terms or other comparable terminology.

The forward-looking statements contained in this document are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this document are not guarantees of future performance, and our expectations may not be realized or the forward-looking events and circumstances may not occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in "Item 1A. Risk Factors.” The forward-looking statements in this document speak only as of the date of this document; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to unduly rely on them.

Table of Contents

PART I

ITEM 1. BUSINESS

References in this annual report on Form 10-K to “Legacy Reserves,” “Legacy,” “we,” “our,” “us,” or like terms refer to Legac
Reserves LP and its subsidiaries.

Legacy Reserves LP

We are a master limited partnership headquartered in Midland, Texas, focused on the acquisition and development of oil and natural gas properties primarily located in the Permian Basin, Mid-Continent and Rocky Mountain regions of the United States. Our primary business objective is to generate stable cash flows allowing us to make cash distributions to our unitholders and to support and increase quarterly cash distributions per unit over time through a combination of acquisitions of new properties and development of our existing oil and natural gas properties.

Our oil and natural gas production and reserve data as of December 31, 2013 are as follows:

- we had proved reserves of approximately 87.6 MMBoe, of which 70% were oil and natural gas liquids (“NGLs”) and 85% were classified as proved developed producing, 2% were proved developed non-producing, and 13% were proved undeveloped; and

- our proved reserves to production ratio was approximately 12.4 years based on the annualized production volumes for the three months ended December 31, 2013.

We have grown primarily through two activities: the acquisition of producing oil and natural gas properties and the development of properties in established producing trends. From 2007 through 2013, we completed 129 acquisitions of oil and natural gas properties for a total of approximately $1.6 billion. These acquisitions of primarily long-lived, oil-weighted assets, along with our ongoing development activities and operational improvements, have allowed us to achieve significant operational and financial growth during this time period.

Business Strategy

The key elements of our business strategy are to:

- Make accretive acquisitions of producing properties generally characterized by long-lived reserves with stable production and reserve development potential;

- Add proved reserves and maximize cash flow and production through development projects and operational efficiencies;

- Maintain financial flexibility; and

- Reduce commodity price risk through oil and natural gas derivative transactions.

Operating Regions

Permian Basin. The Permian Basin, one of the largest and most prolific oil and natural gas producing basins in the United States, was discovered in 1921 and extends over 100,000 square miles in West Texas and southeast New Mexico. It is characterized by oil and natural gas fields with long production histories and multiple producing formations. The Permian Basin has always been our largest operating region containing the vast majority of our drilling locations and development projects. Our producing wells in the Permian Basin are generally characterized as mature oil wells that also produce high-Btu casinghead gas with significant NGL content. Our acquisitions of Permian Basin properties in 2013 constituted approximately 90% of our $108.4 million of total acquisitions during the year.

Table of Contents

Mid-Continent. Our properties in the Mid-Continent region are primarily in the Texas Panhandle and Oklahoma. The vast majority of these properties were acquired through several transactions from April 2007 through October 2008. Our Texas Panhandle wells produce mostly from shallow Granite Wash, Brown Dolomite and Red Cave formations. Our operated properties in the Texas Panhandle are mostly mature oil wells that also produce high-Btu casinghead gas with significant NGL content, while our non-operated properties are mostly mature, low pressure natural gas wells with high NGL content. Our Texas Panhandle fields contain proved reserves of 5.2 MMBoe, are 72% liquids and comprise approximately 56% of our proved reserves in the region. Our most notable field in Oklahoma is the East Binger field in Caddo County, Oklahoma. The East Binger Unit, the majority property in the field, is an active miscible nitrogen injection (tertiary recovery) project that produces from the Marchand Sand. This field contains 3.3 MMBoe of proved reserves that are 81% liquids and comprise approximately 36% of our proved reserves in the region. Our remaining properties in the Mid-Continent region are located in multiple counties in Oklahoma, Texas, Kansas and Arkansas.

Rocky Mountain. We entered the Rocky Mountain region upon completing an acquisition in the Big Horn and Wind River Basins in Wyoming in February 2010 (the "Wyoming Acquisition"). We subsequently added positions in the Powder River Basin through several smaller acquisitions. The properties in Wyoming are largely mature oil wells with a natural water drive that produce primarily from the Dinwoody-Phosphoria, Tensleep and Minnelusa formations. We expanded our footprint in this region with our acquisition of oil properties in North Dakota and Montana in May 2012. The North Dakota properties produce primarily from the Madison and Bakken formations, while the Montana properties produce mostly from the Sawtooth and Bowes formations.

Our proved reserves by area are as follows:

Proved Reserves by Operating Region as of December 31, 2013

Operating Regions	Oil (MBbls)	Natural Gas (MMcf)		NGLs(MBbls)	Total (MBoe)	% Liquids		% PDP		% Total	
Permian Basin	44,127	139,811	(a)	593	68,022	65.7	%	81.8	%	77.6	%
Mid-Continent	3,230	15,637		3,429	9,265	71.9	%	98.0	%	10.6	%
Rocky Mountain	9,549	2,302		14	9,946	96.1	%	93.9	%	11.4	%
Other	124	1,270		39	375	43.5	%	100.0	%	0.4	%
Total	57,030	159,020		4,075	87,608	69.7	%	85.0	%	100.0	%

(a) We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content in those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin are substantially higher than Henry Hub natural gas index prices.

Acquisition Activities

During the year ended December 31, 2013, we completed 16 acquisitions of oil and natural gas properties with an aggregate purchase price of approximately $108.4 million, excluding $11.0 million of non-cash asset retirement obligations, that added approximately 5.1 MMBoe of proved reserves as of year end.

COG 2012 Acquisition. On December 20, 2012, Legacy purchased certain oil and natural gas properties located primarily in the Permian Basin from COG Operating LLC and Concho Oil and Gas, LLC, wholly-owned subsidiaries of Concho Resources Inc., for a net cash purchase price of $502.6 million (the "COG 2012 Acquisition"). The purchase price was financed partially with net proceeds from Legacy's November 2012 public offering of units representing limited partner interests and the remainder with proceeds from Legacy's December private offering of 8%

senior unsecured notes due 2020. The operating results from the COG 2012 Acquisition properties are included in the financial statements to this Form 10-K from the date of the acquisition on December 20, 2012.

Table of Contents

Development Activities

We have also increased reserves and production through development of our existing and acquired properties. Our development projects are primarily focused on drilling and completing new wells, but also include accessing additional productive formations in existing well-bores, formation stimulation, and artificial lift equipment enhancement, as well as secondary (waterflood) and tertiary (miscible CO2 and nitrogen) recovery projects.

As of December 31, 2013, we identified 254 gross (168.9 net) proved undeveloped ("PUD") drilling locations, 145 of which were identified and economically viable at December 31, 2012. The table below details the activity in our PUD locations from December 31, 2012 to December 31, 2013:

	Gross Locations	Net Locations	Net Volume (MBoe)
Balance, December 31, 2012	201	137.7	8,178
PUDs converted to PDP by drilling	(37)	(17.1)	(1,334)
PUDs removed due to performance	(15)	(10.9)	(437)
PUDs removed from future drilling schedule (a)	(2)	(1.1)	(66)
Acquisition activity	5	3.4	211
PUDs removed due to sale	(2)	(2.0)	(337)
Additions due to performance	104	59.3	5,489
Other	—	(0.4)	(39)
Balance, December 31, 2013	254	168.9	11,665

(a) These PUD locations were removed from our PUD inventory because we determined, based upon review of our current inventory and as indicated in our future drilling plans, that these PUD locations are not scheduled to be drilled within five years after initial recognition as proved reserves.

As of December 31, 2013, we identified 75 gross (44.6 net) recompletion and fracture stimulation projects.

Excluding acquisitions, we expect to make capital expenditures of approximately $100 million during the year ending December 31, 2014.

Oil and Natural Gas Derivative Activities

Our business strategy includes entering into oil and natural gas derivative contracts which are designed to mitigate price risk for a majority of our oil, NGL and natural gas production over a three- to five-year period. At December 31, 2013, we had in place oil and natural gas derivatives covering significant portions of our estimated 2014 through 2018 oil and natural gas production. Our derivative contracts are in the form of fixed price swaps, enhanced swaps and three-way collars for NYMEX WTI oil; fixed price swaps and three-way collars for NYMEX Henry Hub, West Texas Waha, ANR-Oklahoma and Rocky Mountain CIG natural gas; and fixed price swaps for the Midland-to-Cushing oil differential.

Marketing and Major Purchasers

For the years ended December 31, 2013, 2012 and 2011, Legacy sold oil, NGL and natural gas production representing 10% or more of total revenues to purchasers as detailed in the table below:

	2013	2012	2011

Enterprise (Teppco) Crude Oil, LP	17 %	12 %	14 %
Plains Marketing, LP	7 %	10 %	11 %

Our oil sales prices are based on formula pricing and calculated either using a discount to NYMEX WTI oil or using the appropriate buyer’s posted price less a regional differential and transportation fee.

Table of Contents

Although we believe we could identify a substitute purchaser if we were to lose any of our oil or natural gas purchasers, the loss could temporarily cause a loss or deferral of production and sale of our oil and natural gas in that particular purchaser’s service area. However, if one or more of our larger purchasers ceased purchasing oil or natural gas altogether, the loss of any such purchaser could have a detrimental impact on our short-term production volumes and our ability to find substitute purchasers for our production volumes in a timely manner, though we do not believe this would have a long-term material adverse effect on our operations.

Competition

We operate in a highly competitive environment for acquiring properties, securing and retaining trained personnel and marketing oil and natural gas. Our competitors may be able to pay more for productive oil and natural gas properties and development projects and to 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 in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months thereby affecting the price we receive for natural gas. Seasonal anomalies, such as mild winters or hotter than normal summers, sometimes lessen this fluctuation. Demand for natural gas and NGLs can be particularly weak in the fall and spring which, coupled with high inventory levels, could result in the shut-in and deferral of production. Our Rockies' oil prices suffer relative to WTI in the winter due to reduced demand for asphaltic crude. Refinery turnarounds in the Permian typically occur in the first quarter, and, historically, we have experienced wider oil differentials during this time.

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

These laws, rules 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 following is a summary of some of the existing laws, rules and regulations to which our operations are subject.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the Federal Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling 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.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the 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 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, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas development and production 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 or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, most 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 were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed of substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other 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 the 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.

The Oil Pollution Act of 1990, as amended or OPA, which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, owners and operators of facilities that store oil above threshold amounts must develop and implement spill response plans.

Safe Drinking Water Act. Our injection well facilities may be regulated under the Underground Injection Control, or UIC, program established under the Safe Drinking Water Act, or SDWA. The state and federal regulations implementing that program require mechanical integrity testing and financial assurance for wells covered under the program. The federal Energy Policy Act of 2005 amended the UIC provisions of the federal SDWA to exclude hydraulic fracturing from the definition of underground injection. Congress has considered bills to repeal this exemption. Further, some states have adopted and others are considering legislation to restrict hydraulic fracturing. Arkansas, New Mexico, Oklahoma, Texas and Wyoming have adopted regulations requiring drilling operators conducting hydraulic fracturing activities to publically disclose the chemicals that are used.

Endangered Species Act. Additionally, environmental laws such as the Endangered Species Act, or ESA, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, 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

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or threatened species, we believe that we are in substantial compliance with the 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.

Air Emissions. The Federal Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources including pursuing the energy extraction sector under a National Enforcement Initiative. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and associated state laws and regulations. Finally, more stringent state and local regulations, such as the EPA rules issued in April 2012, which add new requirements for the oil and gas sector under the New Source Review Program and the National Emission Standards for Hazardous Air Pollutants program, could result in increased costs and the need for operational changes.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency may 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. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

OSHA and Other Laws and Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in compliance with these applicable requirements and with other OSHA and comparable requirements.

On December 7, 2009, the EPA announced its findings that emissions of greenhouse gases present an “endangerment to human health and the environment.” The EPA based this finding on a conclusion that greenhouse gases are contributing to the warming of the earth’s atmosphere and other climate changes. The EPA began to adopt regulations that would require a reduction in emissions of greenhouse gases from certain stationary sources and has required monitoring and reporting for other stationary sources. In late September 2009, the EPA issued rules requiring the reporting of greenhouse gases from large greenhouse gas emissions sources in the United States beginning in 2011 for emissions in 2010. Mandatory reporting requirements for oil and natural gas systems were published on November 30, 2010 and require reporting in 2012 for emissions in 2011. Additional regional, federal or state requirements may be imposed in the future. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our products. Currently, our operations are not adversely impacted by existing state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2013. Additionally, as of the date of this document, we are not aware of any environmental issues or claims that require material capital expenditures during 2014. However, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operations.

Table of Contents

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. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and 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 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, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

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 pro-ration 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 regulate and seek to restrict 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 natural gas liquids within its jurisdiction.

Natural gas regulation. The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale or 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 the FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The FERC's regulations for 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 the underlying properties. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

7

Table of Contents

State regulation. The various states 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. For example, Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. New Mexico currently imposes a 3.75% severance tax on both oil and natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowable 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 amounts 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

As of December 31, 2013, we had 254 full-time employees, including 22 petroleum engineers, 14 accountants, 2 geologists and 11 landmen, none of whom are subject to collective bargaining agreements. We also contract for the services of independent consultants involved in land, engineering, regulatory, accounting, financial and other disciplines as needed. We believe that we have a favorable relationship with our employees.

Offices

We currently lease approximately 65,768 square feet of office space in Midland, Texas at 303 W. Wall Street, Suite 1800, where our principal offices are located. The lease for our Midland office expires in September 2015. In addition to our principal offices, we have regional offices located in Cody, Wyoming for engineering and accounting staff for our Rocky Mountain operations and in The Woodlands, Texas for engineering staff.

Available Information

We make available free of charge on our website, www.legacylp.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.

ITEM 1A. RISK FACTORS

Risks Related to our Business

We may not have sufficient available cash to pay the full amount of our current quarterly distribution, or any distribution at all, following establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

We may not have sufficient available cash each quarter to pay the full amount of our current quarterly distribution, or any distribution at all. The amount of cash we distribute in any quarter to our unitholders may fluctuate significantly from quarter to quarter and may be significantly less than our current quarterly distribution. Under the terms of our partnership agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and the amount of any cash reserves that our general partner establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash

Table of Contents

distributions to our unitholders. Further, our debt agreements contain restrictions on our ability to pay distributions. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

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

If we are not able to acquire additional oil and natural gas reserves on economically acceptable terms, our reserves and production will decline, which would adversely affect our business, results of operations and financial condition and our ability to make cash distributions to our unitholders.

We may be unable to sustain distributions at the current level without making accretive acquisitions or substantial capital expenditures that maintain or grow our asset base. Oil and natural gas reserves are characterized by declining production rates, and our future oil and natural gas reserves and production and, therefore, our cash flow and our ability to make distributions are highly dependent on our success in economically finding or acquiring additional recoverable reserves and efficiently developing and exploiting our current reserves. Further, the rate of estimated decline of our oil and natural gas reserves may increase if our wells do not produce as expected. We may not be able to find, acquire or develop additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our future growth may be limited because we distribute all of our available cash to our unitholders, and potential future disruptions in the financial markets may prevent us from obtaining the financing necessary for growth and acquisitions.

Since we will distribute all of our available cash (as defined in our partnership agreement) to our unitholders, our growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations. Further, since we depend on financing provided by commercial banks and other lenders and the issuance of debt and equity securities to finance any significant growth or acquisitions, potential future disruptions in the global financial markets and any associated severe tightening of credit supply may prevent us from obtaining adequate financing from these sources, and, as a result, our ability to grow, both in terms of additional drilling and acquisitions, will be limited.

Increases in the cost of or failure of costs to adjust downward for drilling rigs, service rigs, pumping services and other costs in drilling and completing wells could reduce the viability of certain of our development projects.

Higher oil and natural gas prices may increase the rig count and thus the cost of rigs and oil field services necessary to implement our development projects while also decreasing their availability. Increased capital requirements for our projects will result in higher reserve replacement costs which could reduce cash available for distribution. Higher project costs could cause certain of our projects to become uneconomic and therefore not to be implemented, reducing our production and cash available for distribution. Decreased availability of drilling equipment and services could significantly impact the planned execution of our scheduled development program.

Table of Contents

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 gas properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

Lower oil and natural gas prices may not only decrease our revenues, but also reduce the amount of oil and natural gas that we can produce economically. For example, the drastically lower oil and natural gas prices experienced in the fourth quarter of 2008 rendered more than half of the development projects we had planned at such time uneconomic and resulted in a substantial downward adjustment to our estimated proved reserves. Further, deteriorating commodity prices may cause us to recognize impairments in the value of our oil and natural gas properties. For example, in the year ended December 31, 2013 we incurred impairment charges of $85.8 million, of which $78.0 million was driven largely by commodity price changes. 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 related to depressed commodity prices, which could have a material adverse effect on our results of operations in the period taken.

Fluctuations in price and demand for our natural gas and NGLs may force us to shut in a significant number of our producing wells, which may adversely impact our revenues and ability to pay distributions to our unitholders.

We are subject to great fluctuations in the prices we are paid for our natural gas due to a number of factors including regional demand, weather, demand for NGLs which are recovered from our gas stream, and new natural gas pipelines. Drilling in shale resources has developed large amounts of new natural gas supplies, both from natural gas wells and associated natural gas from oil wells, that have depressed the prices paid for our natural gas and NGLs, and we expect the shale resources to continue to be drilled and developed by our competitors. We also face the potential risk of shut-in natural gas due to high levels of natural gas and NGL inventory in storage, weak demand due to mild weather and the effects of any economic downturns on industrial demand. Lack of NGL storage in Mont Belvieu where our West Texas and New Mexico NGLs are shipped for processing could cause the processors of our natural gas to curtail or shut-in our natural gas wells and potentially force us to shut-in oil wells that produce associated natural gas. For example, following past hurricanes, certain Permian Basin natural gas processors were forced to shut down their plants due to the shutdown of the Texas Gulf Coast NGL fractionators, requiring us to vent or flare the associated natural gas from our oil wells. There is no certainty we will be able to vent or flare natural gas again due to potential changes in regulations. Furthermore, we may encounter problems in restarting production of previously shut-in wells.

Our commodity and interest rate derivative activities may limit our ability to profit from price gains, could result in cash losses and expose us to counterparty risk and as a result could reduce our cash available for distributions.

We have entered into, and we expect in the future to enter into, oil and natural gas derivative contracts intended to offset the effects of commodity price volatility related to a significant portion of our oil and natural gas production. Many derivative instruments that we employ 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.

In addition, we have entered into, and we may in the future enter into, interest rate swap contracts intended to offset the effects of interest rate volatility related to our outstanding indebtedness under our revolving credit facility. These instruments require us to make cash payments to the extent applicable floating interest rates are less than our contracted fixed rates, thereby limiting our ability to realize the benefit of declining interest rates.

There is always risk that counterparties in any commodity or interest rate derivative transaction cannot or will not perform under our derivative contracts. If a counterparty fails to perform and the derivative transaction is terminated, our cash flow and ability to pay distributions could be adversely impacted.

Table of Contents

Further, if our actual production and sales for any period are less than our expected production covered by derivative contracts and sales for that period (including reductions in production due to involuntary shut-ins or 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 derivative contracts without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. Under our revolving credit facility, we are prohibited from entering into commodity derivative contracts covering all of our production, and we therefore retain the risk of a price decrease on our volumes not covered by commodity derivative contracts.

An increase in the differential between the West Texas Intermediate (“WTI”) or other benchmark prices of oil and the wellhead price we receive for our production could adversely affect our operating results and financial condition.

The prices that we receive for our oil production sometimes reflect a discount to the relevant benchmark prices, such as WTI, that are used for calculating derivative positions. The difference between the benchmark price and the price we receive is called a differential. Increases in the differential between the benchmark prices for oil and the wellhead price we receive could adversely affect our operating results and financial condition. For example, our realized oil price decreased $3.84 per Bbl to $85.78 per barrel for the year ended December 31, 2012 from $89.62 per barrel for the year ended December 31, 2011. This decrease in realized oil prices was primarily caused by a larger average oil differential of $2.75 per barrel as well as a lower average WTI price. This increased oil differential was largely due to a significant increase in the Midland-Cushing/WTI differential in 2012 compared to 2011. Significant differentials could adversely affect our operating results and financial condition.

Due to regional fluctuations in the actual prices received for our natural gas production, the derivative contracts we enter into may not provide us with sufficient protection against price volatility since they are based on indexes related to different and remote regional markets.

We sell our natural gas into local markets, the majority of which is produced in West Texas, Southeast New Mexico, the Texas Panhandle, Central Oklahoma and Wyoming and shipped to the Midwest, West Coast and Texas Gulf Coast. These regions account for over 90% of our natural gas sales. Currently we use swaps on Waha, ANR-Oklahoma and CIG-Rockies natural gas prices. While we are paid a local price indexed to or closely related to Waha, ANR-Oklahoma and CIG-Rockies, these indexes are heavily influenced by prices received in remote regional consumer markets less transportation costs and thus may not be effective in protecting us against local price volatility.

The substantial restrictions and financial covenants of our revolving credit facility, any negative redetermination of our borrowing base by our lenders and any potential disruptions of the financial markets could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We depend on our revolving credit facility for future capital needs. Our revolving credit facility, which matures on March 10, 2016, limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. As of February 20, 2014, our borrowing base was $800 million and we had approximately $425.9 million available for borrowing.

Our revolving credit facility restricts, among other things, our ability to incur debt and pay distributions to our unitholders, and requires us to comply with certain financial covenants and ratios. We may not be able to comply with these restrictions and covenants in the future and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, such as any potential disruptions in the financial markets. Our failure to comply with any of the restrictions and covenants under our revolving credit facility could result in a default under our revolving credit facility. A default under our revolving credit facility could cause all of our existing indebtedness, including our $300 million 8% senior unsecured notes maturing on December 1, 2020 and our $250 million 6.625% senior unsecured notes maturing on December 1, 2021 (collectively, the "Senior Notes"), to be immediately due and payable.

Table of Contents

We are prohibited from borrowing under our revolving credit facility to pay distributions to unitholders if the amount of borrowings outstanding under our revolving credit facility reaches or exceeds 100% of the borrowing base, which is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will redetermine the borrowing base based on an engineering report with respect to our oil and natural gas reserves, which will take into account the prevailing oil and natural gas prices and differentials at such time. Any time our borrowings meet or exceed 100% of the then specified borrowing base, our ability to pay distributions to our unitholders in any such quarter is solely dependent on our ability to generate sufficient cash from our operations after such cash flow is first used to cure any borrowing base deficiency.

Outstanding borrowings in excess of the borrowing base must be repaid, and, if mortgaged properties represent less than 80% of total value of oil and natural gas properties used to determine the borrowing base, we must pledge other oil and natural gas properties as additional collateral. We may not have the financial resources in the future to make any mandatory principal prepayments required under our revolving credit facility.

The occurrence of an event of default or a negative redetermination of our borrowing base, such as a result of lower commodity prices or a deterioration in the condition of the financial markets, could adversely affect our business, results of operations, financial condition and our ability to make distributions to our unitholders.

Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operation — Financing Activities.”

Restrictive covenants under the indentures governing our Senior Notes may adversely affect our operations.

The indentures governing our the Senior Notes contains, and any future indebtedness we incur may contain, a number of restrictive covenants that impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our restricted subsidiaries;
- pay distributions on, redeem or purchase our units or redeem or purchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all our substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries; and
- engage in certain business activities.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

A failure to comply with the covenants in the indentures governing the Senior Notes or any future indebtedness could result in an event of default under the indentures governing the Senior Notes, our revolving credit facility, or any future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. In addition, complying with these covenants may make it more difficult for us to successfully execute our business strategy and compete against companies that are not subject to such restrictions.

Table of Contents

Our debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities.

As of February 20, 2014, we had total long-term debt of approximately $924 million. Our existing and future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on terms acceptable to us;
- covenants in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- our access to the capital markets may be limited;
- our borrowing costs may increase;
- we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders; and
- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms or at all.

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

No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. 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.

Further, the present value of future net cash flows from our proved reserves 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 Financial Accounting Standards Board ("FASB") 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 natural gas and oil industry in general.

13

Table of Contents

Our business depends on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities would interfere with our ability to market the oil and natural gas we produce.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The amount of oil 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, oversupply of oil due to nearby refinery outages, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. 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 pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our development projects require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.

We make and expect to continue to make substantial capital expenditures in our business for the development, production and acquisition of oil and natural gas reserves. These expenditures will reduce our cash available for distribution. We intend to finance our future capital expenditures with cash flow from operations and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower oil and/or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our revolving credit facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas production and reserves, and could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We do not control all of our operations and development projects and failure of an operator of wells in which we own partial interests to adequately perform could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Many of our business activities are conducted through joint operating agreements under which we own partial interests in oil and natural gas wells.

If we do not operate wells in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The success and timing of our development projects on properties operated by others is outside of our control.

The failure of an operator of wells in which we own partial interests to adequately perform operations, or an operator's breach of the applicable agreements, could reduce our production and revenues and could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Table of Contents

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, results of operations, financial condition and our ability to make cash 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.

In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;
- adverse weather conditions;
- facility or equipment malfunctions;
- title disputes;
- pipeline ruptures or spills;
- collapses of wellbore, casing or other tubulars;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Increases in interest rates could adversely affect our business, results of operations, cash flows from operations and financial condition, and cause a decline in the demand for yield-based equity investments such as our units.

Since all of the indebtedness outstanding under our revolving credit facility is at variable interest rates, we have significant exposure to increases in interest rates. As a result, our business, results of operations and cash flows may be adversely affected by significant increases in interest rates. Further, an increase in interest rates may cause a corresponding decline in demand for equity investments, in particular for yield-based equity investments such as our units. Any reduction in demand for our units resulting from other more attractive investment opportunities may cause the trading price of our units to decline.

Table of Contents

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.

We may not achieve the expected results of any acquisition we complete, and any adverse conditions or developments related to any such acquisition may have a negative impact on our operations and financial condition.

Further, even if we complete any acquisitions, which we would expect to increase pro forma distributable cash per unit, actual results may differ from our expectations and the impact of these acquisitions may actually result in a decrease in pro forma distributable cash per unit. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs;
- an inability to successfully integrate the businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility 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 environmental and other 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;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- the loss of key purchasers.

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

Also, our reviews of newly acquired properties are inherently incomplete because it is generally 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 fully assess 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.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may be materially different from those presently identified, which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

16

Table of Contents

The inability of one or more of our customers to meet their obligations may adversely affect our financial condition and results of operations.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our oil, natural gas and interest rate derivative transactions expose us to credit risk in the event of nonperformance by counterparties.

We depend on a limited number of key personnel who would be difficult to replace.

Our operations are dependent on the continued efforts of our executive officers, senior management and key employees. The loss of any member of our senior management or other key employees could negatively impact our ability to execute our strategy.

We may be unable to compete effectively, which could have an adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our competitors not only explore 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 productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration and development activities during periods of low oil and natural gas market prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with these companies could have an adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results could be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to continue to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet certain reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our units.

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 exploration and production operations are subject to complex and stringent laws and regulations. In order 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

Table of Contents

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. All such costs may have a negative effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

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 the exploration for, and the production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

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.

Final rules regulating air emissions from natural gas production operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

On April 17, 2012, the EPA approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. We are currently reviewing this new rule and assessing its potential impacts. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

Our sales of oil, natural gas, NGLs and other energy commodities, and related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission (the “CFTC”) hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas, NGLs or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting

Table of Contents

and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”), which was enacted in July 2010, provides for statutory and regulatory requirements for certain derivative transactions, broadly referred to as “swaps” and which include some oil and gas transactions, including oil and gas hedging transactions, and interest rate swaps. Swaps designated by the CFTC or falling within classes of swaps designated by the CFTC are or will be required to be submitted for clearing on a derivative clearing organization (“DCO”) and, if accepted for clearing, cleared on the DCO. To date, the CFTC has designated only certain interest rate swaps and index credit default swaps for mandatory clearing. Transactions in swaps accepted for clearing must be executed on a board of trade designated as a contract market or a swap execution facility if such swaps are made available for trading on such a board of trade or swap execution facility. The Act provides an exception from application of the Act's clearing and trade execution requirements that certain commercial end-users may elect for swaps they use to hedge or mitigate commercial risks ("End-User Exception"). Although we believe we will be able to elect such exception with respect to most, if not all, of the swaps we enter that are subject to mandatory clearing, if we cannot do so with respect to many of the swaps we enter into, our ability to execute our hedging program efficiently will be adversely affected.

In the event we do not qualify for the End-User Exception, we anticipate that, under regulations adopted under the Act and relevant DCO and other rules, we will be required to post margin in the form of cash collateral for those of our derivative transactions constituting swaps (including our interest rate swaps and commodities-related swaps) that we clear on a DCO. Moreover, the Act requires the CFTC and the federal regulators of banks and other financial institutions to adopt regulations imposing margin requirements for non-cleared swaps that, when adopted, could, in certain circumstances, require us to post margin in the form of cash or other types of collateral for any non-cleared swaps into which we enter. Posting margin in the form of cash collateral with respect to our swaps could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures, distributions to unitholders or other partnership purposes. A requirement to post margin, especially in the form of cash collateral, with respect to any cleared or non-cleared swaps we enter could reduce our ability to execute strategic hedges to reduce commodity price uncertainty and, thus, to protect cash flows. In addition, even if we are not required to post margin for our swaps or to post margin of only immaterial amounts, the banks and other derivatives dealers who are the contractual counterparties to our swaps will be required to comply with the Act's new requirements, and the costs of their compliance will likely be passed on to customers, including us, thus increasing our costs of engaging in hedging transactions, decreasing the benefits of those transactions to us and reducing our cash flows. We currently hedge only with current or former lenders under our Current Credit Agreement, which have collateral in our oil and natural gas properties and do not require us to post cash collateral.

As required by the Act, the CFTC must also adopt limits on the positions that a party may hold in certain contracts relating to physical commodities. After previously adopted position limits rules were vacated by the United States District Court for the District of Columbia, the CFTC has proposed new regulations setting limits on the positions that a party may hold for its own account in specified core futures contracts relating to certain physical commodities, including NYMEX contracts relating to WTI crude oil and Henry Hub natural gas, as well as options and swaps that are economically equivalent to such future contracts, and futures contracts, options contracts, swaps, basis contracts and commodity index contracts linked to such futures contracts or such physical commodities. Under the proposed rule, such position limits would be subject to certain exemptions, including one for positions that qualify as bona fide hedging positions under the proposed rule. If the rule is adopted as proposed and for any reason our contracts relating to such commodities, if any, fail to qualify for an exemption from the position limits, our ability to execute strategic hedges to reduce commodity price uncertainty, and thus to protect cash flows, could be impaired.

Pursuant to the Act’s requirements, the banking regulators have adopted a rule that could require certain of the counterparties to our commodity derivative contracts to spin off some of their derivatives activities to separate entities. Those separate entities could be our counterparties to our swaps and may not be as creditworthy as our

19

Table of Contents

current counterparties. If such a counterparty were unable to, or failed to, perform its obligations under swaps to which we were party, our business, results of operations, financial condition and our ability to make cash distributions to our unitholders could be adversely impacted.
The Act and the rules relating to derivative transactions adopted thereunder may significantly increase our cost of entering into and maintaining commodity derivative contracts, materially alter the terms on which we enter derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives contracts as a result of the Act and the related rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make distributions to our unitholders. Finally, the Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our oil and natural gas revenues could therefore be adversely affected if a consequence of the Act is to lower commodity prices. Any of these consequences could have a material adverse impact on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

Congress has considered 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 an important and 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 Legacy completes and produces. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. In addition, some states have adopted and others are considering legislation to restrict hydraulic fracturing. Several states including Texas and Wyoming have adopted or are considering legislation requiring the disclosure of hydraulic fracturing chemicals. Public disclosure of chemicals used in the fracturing process, which 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. In addition any additional level of regulation could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Units eligible for future sale may have adverse effects on our unit price and the liquidity of the market for our units.

We cannot predict the effect of future sales of our units, or the availability of units for future sales, on the market price of or the liquidity of the market for our units. Sales of substantial amounts of units, or the perception that such sales could occur, could adversely affect the prevailing market price of our units. Such sales, or the possibility of such sales, could also make it difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. The founding investors (the "Founding Investors") and their affiliates, including members of our management, own approximately 18% of our outstanding units. We granted the Founding Investors certain registration rights to have their units registered under the Securities Act. Upon registration, these units will be eligible for sale into the market without volume limitations. Because of the substantial size of the Founding Investors' holdings, the sale of a significant portion of these units, or a perception in the market that such a sale is likely, could have a significant impact on the market price of our units.

Table of Contents

Our acquisitions may prove to be worth less than we paid, or provide less than anticipated proved reserves, production or cash flow because of uncertainties in evaluating recoverable reserves, well performance and potential liabilities as well as uncertainties in forecasting oil and gas prices and future development, production and marketing costs. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, development potential, well performance, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Our estimates of future reserves and estimates of future production for our acquisitions and related forecasts of anticipated cash flow therefrom, are initially based on detailed information furnished by the sellers and subject to review, analysis and adjustment by our internal staff, typically without consulting with outside petroleum engineers. Such assessments are inexact and their accuracy is inherently uncertain and our proved reserves estimates and cash flow forecasts therefrom may exceed actual acquired proved reserves or the estimates of future cash flows therefrom. In connection with our assessments, we perform a review of the acquired properties included in our acquisitions that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

Also, our reviews of the properties included in our acquisitions are inherently incomplete because it is generally 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 fully assess 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.

Risks Related to Our Limited Partnership Structure

Our Founding Investors, including members of our management, own an approximately 18% limited partner interest in us and control our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner has conflicts of interest and limited fiduciary duties, which may permit it to favor its own interests to the detriment of our unitholders.

Our Founding Investors, including members of our management, own an approximately 18% limited partner interest in us and therefore have the ability to influence the election of the members of the board of directors of our general partner. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners, our Founding Investors and their affiliates. Conflicts of interest may arise between our Founding Investors and their affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires our Founding Investors or their affiliates, other than our executive officers, to pursue a business strategy that favors us;
- our general partner is allowed to take into account the interests of parties other than us, such as our Founding Investors, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- our Founding Investors and their affiliates (other than our executive officers and their affiliates) may engage in competition with us;

21

Table of Contents

- our general partner has limited its liability and reduced its fiduciary duties under our partnership agreement and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of purchasing units, unitholders consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, and reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or a growth capital expenditure, which does not. Such determination can affect the amount of cash that is distributed to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner controls the enforcement of obligations owed to us by it and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants, or others to perform services for us.

Our partnership agreement restricts the voting rights of those unitholders owning 20% or more of our units.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such 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 the unitholders' ability to influence the manner or direction of management.

Our Founding Investors and their affiliates (other than our executive officers and their affiliates) may compete directly with us.

Our Founding Investors and their affiliates, other than our general partner and our executive officers and their affiliates, are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, our Founding Investors or their affiliates, other than our general partner and our executive officers and their affiliates, may acquire, develop and operate oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to acquire, develop or operate those assets.

Cost reimbursements due our general partner and its affiliates will reduce our cash available for distribution to our unitholders.

Prior to making any distribution on our outstanding units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. Any such reimbursement will be determined by our general partner in its sole discretion. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us. The reimbursement of expenses of our general partner and its affiliates could adversely affect our ability to pay cash distributions to our unitholders.

Table of Contents

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 standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- provides that our general partner is entitled to make other decisions in "good faith" if it believes that the decision is in our best interest;
- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us, as determined by our general partner in good faith, and that, 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; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our unitholders 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 the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

Our partnership agreement permits our general partner to redeem any partnership interests held by a limited partner who is a non-citizen assignee.

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, our general partner may redeem the units held by the limited partner at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, our general partner may elect to treat the limited partner as a non-citizen assignee. A non-citizen assignee is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

We may issue an unlimited number of additional units or other equity securities without the approval of our unitholders, which would dilute their existing ownership interest in us.

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units or other equity securities. The issuance by us of additional units or other equity securities of equal or senior rank will have the following effects:

- our unitholders’ proportionate ownership interests in us will decrease;
- the amount of cash available for distribution on each unit may decrease;

Table of Contents

- the risk that a shortfall in the payment of our current quarterly distribution will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the units may decline.

The liability of our unitholders 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. In some states, including Delaware, a limited partner is only liable if he participates in the "control" of the business of the partnership. These statutes generally do not define control, but do permit limited partners to engage in certain activities, including, among other actions, taking any action with respect to the dissolution of the partnership, the sale, exchange, lease or mortgage of any asset of the partnership, the admission or removal of the general partner and the amendment of the partnership agreement. Our unitholders could, however, be liable for any and all of our obligations as if our unitholders were 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
- our unitholders' right to act with other unitholders to take other actions under our partnership agreement constitutes "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

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 a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the distribution, limited partners who received an impermissible 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. Substituted limited partners are liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such substitute limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Unitholders

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

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

Despite the fact that we are a limited partnership under Delaware law, it is possible, in certain circumstances, for a partnership such as ours to be treated as a corporation for U.S. federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for U.S. federal income tax

Table of Contents

purposes or otherwise subject us to taxation as an entity. If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which currently has a top marginal rate of 35%, and would likely pay state and local income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available to pay distributions to our 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.

In addition, changes in current state law may subject us to 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. For example, we are subject to an entity-level state tax on the portion of our gross income that is apportioned to Texas. If any additional states were to impose a tax upon us as an entity, the cash available for distribution to our unitholders would be reduced.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time members of the U.S. Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our units.

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

Both the Obama Administration and members of the U.S. Congress have during past legislative sessions proposed changes that would, if enacted into law, 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 proposed in the current legislative session, and if proposed and enacted, how soon any such changes could become effective. The passage of any legislation with similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

Our unitholders may be required to pay taxes on their share of our 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 that could be different in amount than the cash we distribute, a unitholder's share of our taxable income will be taxable to the unitholder, which may require the payment of U.S. federal income taxes and, in some cases, state and local income taxes on the unitholder's share of our taxable income, whether or not the unitholder receives 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 their share of our taxable income.

Table of Contents

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

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

A successful IRS contest of the U.S. federal income tax positions we take may adversely affect the market for our units, and the costs of any contest will reduce our cash available for distribution to our unitholders.

We have not requested any 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 our counsel's conclusions or 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 disagree 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 result in a reduction in cash available to pay distributions to our unitholders and thus will be borne indirectly by our unitholders.

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

Investment in our units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from U.S. federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

Tax gain or loss on the disposition of our units could be more or less than expected because prior distributions in excess of allocations of income will decrease our unitholders tax basis in their units.

If our unitholders sell any of their units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those units. Prior distributions to our unitholders in excess of the total net taxable income they were allocated for a unit, which decreased their tax basis in that unit, will, in effect, become taxable income to our unitholders if the unit is sold at a price greater than their tax basis in that unit, even if the price our unitholders receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to our unitholders due to the potential recapture items, including depreciation, depletion and intangible drilling cost 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.

We will treat each purchaser of our 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, we will adopt depletion, depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. Our counsel is unable to opine as to the validity of such filing positions. 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 on the sale of units and could have a negative impact on the value of our units or result in audits of and adjustments to our unitholders' tax returns.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the 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 cover a short sale of units may be considered as having disposed of the loaned units, he 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. Our counsel has not rendered an opinion regarding the treatment of a unitholder where our units are loaned to a short seller to cover a short sale of our units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult with their tax advisor about whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Our unitholders may be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our units.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently do business and own assets in Texas, New Mexico, Oklahoma, Alabama, Mississippi, Wyoming, North Dakota, Colorado, Arkansas, Louisiana, Kansas, Montana and Utah. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all United States federal, state and local tax returns that may be required of such unitholder. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our units.

We will be considered to have technically terminated for U.S. federal income tax purposes due to a sale or exchange of 50% or more of our interests within a twelve-month period.

We will be considered to have technically terminated our partnership for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest 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 relief was not available, as described below) for one fiscal year and could result in a 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 his taxable income for the year of termination. Our termination currently 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 termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

Table of Contents

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

As of December 31, 2013 we owned interests in producing oil and natural gas properties in 664 fields in the Permian Basin, Texas Panhandle, Wyoming, North Dakota, Montana, Oklahoma and several other states, from 8,071 gross productive wells of which 3,734 are operated and 4,337 are non-operated. The following table sets forth information about our proved oil and natural gas reserves as of December 31, 2013. 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. For a definition of “standardized measure,” please see the glossary of terms at the beginning of this annual report on Form 10-K.

	As of December 31, 2013 Proved Reserves			Standardized Measure	
Field	MMBoe	R/P (a)	% Oil and NGLs	Amount (b)	% of Total
				($ in Millions)	
Spraberry/War San (c)	12.7	15.3	67 %	$ 237.5	15.3 %
Texas Panhandle	5.2	13.2	72	72.5	4.6
New Mexico Lower Abo	2.6	6.1	57	65.1	4.2
East Binger	3.3	12.8	81	60.7	3.9
Lea	2.0	8.0	76	50.4	3.2
Jalmat	2.4	22.6	93	47.6	3.1
Jordan	2.3	10.4	91	44.4	2.9
Deep Rock	1.8	17.9	96	43.9	2.8
Denton	2.2	15.1	86	42.0	2.7
Langlie Mattix	2.0	20.6	88	39.3	2.5
Total — Top 10 fields	36.5	12.9	76 %	$ 703.4	45.2 %
All others	51.1	12.0	66	853.6	54.8
Total	87.6	12.4	70 %	$ 1,557.0	100.0 %

(a) Reserves as of December 31, 2013 divided by annualized fourth quarter production volumes.

(b) Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure.

Table of Contents

(c) As the Spraberry/War San field contains 12.7 MMBoe, or 14.5% of total proved reserves of 87.6 MMBoe, the following table presents the production, by product, for the Spraberry/War San field for the last three fiscal years:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands, except daily production)		
Spraberry/War San Field Production:			
Oil (MBbls)	555	510	475
Natural gas liquids (Mgal)	240	428	346
Natural gas (MMcf)	1,678	1,599	1,514
Total (Mboe)	840	787	735
Average daily production (Boe per day)	2,301	2,150	2,014

Summary of Oil and Natural Gas Properties and Projects

Our most significant fields are the Spraberry/War San, Texas Panhandle, New Mexico Lower Abo, East Binger, Lea, Jalmat, Jordan, Deep Rock, Denton and Langlie Mattix. As of December 31, 2013, these ten fields accounted for approximately 45% of our Standardized Measure and 42% of our total estimated proved reserves.

Spraberry/War San Field. The Spraberry/War San field is located in Andrews, Howard, Midland, Martin, Reagan and Upton Counties, Texas. This Spraberry/War San field summary includes wells in the War San field which produce from the same formations and in the same area as our Spraberry field wells. This field produces from Spraberry and Wolfcamp age formations from 5,000 to 11,000 feet. We operate 236 active wells (231 producing, 5 injecting) in this field with working interests ranging from 5.5% to 100% and net revenue interests ranging from 4.2% to 90.8%. We also own another 134 non-operated wells (132 producing, 2 injecting). As of December 31, 2013, our properties in the Spraberry/War San field contained 12.7 MMBoe (67% liquids) of net proved reserves with a standardized measure of \$237.5 million. The average net daily production from this field was 2,268 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) for this field is 15.3 years based on the annualized fourth quarter production rate.

24 wells were drilled on our properties in the Spraberry/War San field in 2013. We have identified 75 more proved undeveloped projects, primarily 40-acre infill drilling locations, and ten behind-pipe or proved developed non-producing recompletion projects in this field. We have also identified several unproved drilling locations in this field.

Texas Panhandle Fields. The Texas Panhandle fields are located in Carson, Gray, Hartley, Hutchinson, Moore, Potter, Sherman and Wheeler Counties, Texas. The fields are produced from multiple formations of Permian age which primarily include the shallow Granite Wash, Brown Dolomite, and Red Cave formations from 2,500 to 4,000 feet. We operate 620 wells (579 producing, 41 injecting) in the Texas Panhandle fields with working interests ranging from 33.3% to 100% and net revenue interests ranging from 25% to 100%. We also own another 413 non-operated wells (401 producing, 12 injecting). As of December 31, 2013, our properties in the Texas Panhandle fields contained 5.2 MMBoe (72% liquids) of net proved reserves with a standardized measure of \$72.5 million. The average net daily production from these fields was 1,079 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) for these fields is 13.2 years based on the annualized fourth quarter production rate.

New Mexico Lower Abo. The Lower Abo horizontal drilling play includes several fields located in Eddy, Lea and Chaves Counties, New Mexico. The primary fields in this play are Crow Flats, Dog Canyon and County Line Tank. The producing formation in all of these fields is the Lower Abo at depths of 6,350 to 9,500 feet. Legacy acquired all of our wells in this play as part of the COG 2012 Acquisition. We operate 39 wells in the Lower Abo play with working interests ranging from 25% to 100% and net revenue interests ranging from 20.6% to 87.5%. We also own 18 non-operated wells. There has been considerable drilling activity in this area during recent years by the previous operator and operators of our non-operated wells, as 29 of our 39 operated wells have come online since January 1, 2010, which is resulting in significant flush production from these wells. As of December 31, 2013, our properties in the Lower Abo play contained 2.6 MMBoe (57% liquids) of net proved reserves with a standardized measure of $65.1 million. The average net daily production from this field was 1,171 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) for the field is 6.1 years based on the annualized fourth quarter production rate, which is materially impacted by the aforementioned flush production from recent drilling activity by the prior operator. We expect this production rate to continue to drop materially in 2014. Our engineers have identified five proved undeveloped drilling projects as well as several unproved drilling projects in this area.

East Binger Field. The East Binger field is located in Caddo County, Oklahoma. The Marchand Sand, at depths of 9,700 to 10,100 feet, is the primary reservoir in the East Binger field. The East Binger Unit, the major property in the field, is an active miscible nitrogen injection project and is operated by Binger Operations, LLC (BOL), of which Legacy owns 50%. BOL operates 85 wells (59 producing, 26 injecting) in the East Binger field, and Legacy owns a working interest of 55.67% and net revenue interest of 46.9% in the East Binger Unit. As of December 31, 2013, our properties in the East Binger field contained 3.3 MMBoe (81% liquids) of net proved reserves with a standardized measure of $60.7 million. The average net daily production from this field was 708 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) for the field is 12.8 years based on the annualized fourth quarter production rate. We have identified five proved undeveloped drilling locations in this field.

Lea Field. The Lea field is located in Lea County, New Mexico. Our Lea field properties consist primarily of interests in the Lea Unit and Lea Federal Unit. The majority of the production from these properties is from the Bone Spring formation at depths of 11,100 feet to 16,800 feet. These properties also produce from the Morrow, Devonian, Delaware and Pennsylvania formations at depths ranging from 11,150 feet to 14,500 feet. We operate 30 wells (26 producing, 4 injecting) in the Lea Field with working interests ranging from 12.5% to 100% and net revenue interests ranging from 15.0% to 81.3%. As of December 31, 2013, our properties in the Lea Field contained 2.0 MMBoe (76% liquids) of net proved reserves with a standardized measure of $50.4 million. The average net daily production from this field was 678 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) of the field is 8.0 years based on the annualized fourth quarter production rate. Our engineers have identified two additional proved and several unproved undeveloped horizontal Bone Spring drilling locations in the field.

Jalmat Field. The Jalmat field is located in Lea County, New Mexico. Our Jalmat field properties consist primarily of interests in the Cooper Jal Unit, Jalmat Yates Unit and South Langlie Jal Unit. All of the production in the field is from the Yates, Seven Rivers and Queen formations which are under waterflood at depths of 2,900 to 3,800 feet. We operate 135 wells (99 producing, 36 injecting) in the field with working interests ranging from 68.8% to 81.8% and net revenue interests ranging from 53.2% to 70.7%. We also own 21 non-operated wells in the field. As of December 31, 2013, our properties in the Jalmat field contained 2.4 MMBoe (93% liquids) of net proved reserves with a standardized measure of $47.6 million. The average net daily production from this field was 289 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) for the field is 22.6 years based on the annualized production rate. Our engineers have identified seven proved undeveloped infill drilling projects and 10 behind-pipe or proved developed non-producing projects in the field.

Jordan Field. The Jordan field is located in Ector and Crane Counties, Texas. The field produces under waterflood from the San Andres formation at depths of 3,100 to 3,800 feet. We operate 116 wells (87 producing, 29 injecting) in the field with working interests ranging from 53.1% to 95.0% and net revenue interests ranging from 39.8% to 76.2%. We also own a 35.9% non-operated working interest and a 29.7% net revenue interest in the Jordan University Unit which contains 180 wells (145 producing, 35 injecting). As of December 31, 2013, our properties in the Jordan field contained 2.3 MMBoe (91% liquids) of net proved reserves with a standardized measure of $44.4 million. The average net daily production from the field was 613 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) of the field is 10.4 years based on the annualized fourth quarter production rate. Our engineers have identified 36 proved undeveloped infill drilling projects, and 10 behind-pipe or proved developed non-producing projects and several unproved drilling locations in the field.

Deep Rock Field. The Deep Rock field is located in Andrews County, Texas. Most of the production in the field is from the Glorieta formation at depths of 5,630 to 6,000 feet. The field also produces from the Pennsylvanian, Devonian and Ellenburger formations at depths from 6,000 to 12,200 feet. We acquired the majority of our wells in this field as part of the COG 2012 Acquisition. We operate 175 wells (132 producing, 43 injecting) in the field with working interests ranging from 26.7% to 100% and net revenue interests ranging from 5.8% to 87.5%. We also own

Table of Contents

210 non-operated wells (171 producing, 39 injecting). As of December 31, 2013, our properties in the Deep Rock field contained 1.8 MMBoe (96% liquids) of net proved reserves with a standardized measure of $43.9 million. The average net daily production from this field was 282 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) for the field is 17.9 years based on the annualized production rate. Our engineers have identified four proved undeveloped projects and one proved developed non-producing project in the field. We also have several additional unproved drilling locations and multiple unproved developed non-producing projects in the field.

Denton Field. The Denton field is located in Lea County, New Mexico. The Devonian Formation at depths of 11,000 to 12,700 feet is the primary reservoir in the Denton field. Additional production has been developed in the Wolfcamp Formation at depths of 8,900 to 9,600 feet. We operate 23 wells in the Denton field with working interests ranging from 25% to 100% and net revenue interests ranging from 21.8% to 87.5%. We also own another nine wells (seven producing, two injecting) with a 15% non-operated working interest and a 13.1% net revenue interest. As of December 31, 2013, our properties in the Denton field contained 2.2 MMBoe (86% liquids) of net proved reserves with a standardized measure of $42.0 million. The average net daily production from this field was 406 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) for the field is 15.1 years based on the annualized fourth quarter production rate.

Langlie Mattix Field. The Langlie Mattix field is located in Lea County, New Mexico. The primary reservoir in this field is the Queen formation at depths of 3,400 to 3,800 feet. We operate 97 wells (72 producing, 25 injecting) in the Langlie Mattix Penrose Sand Unit, a subdivision of the Langlie Mattix Field, with a 59.0% average working interest and a 50.7% average net revenue interest. We also operate 48 wells (47 producing, 1 injecting) in the Skelly Penrose A Unit with a 100% working interest and a 86.8% net revenue interest. We also operate 78 wells (37 producing, 41 injecting) in the Langlie Jal Unit with a 70.3% working interest and a 55.7% net revenue interest, as well as five other properties with eight active producing wells with an average net working interest of 95.9% and 80.8% average net revenue interests. As of December 31, 2013, our properties in the Langlie Mattix field contained 2.0 MMBoe (88% liquids) of net proved reserves with a standardized measure of $39.3 million. The average net daily production from this field was 264 Boe/d for the fourth quarter of 2013. The estimated reserve life (R/P) for the field is 20.6 years based on the annualized fourth quarter production rate.

The Langlie Mattix Penrose Sand Unit was drilled in the late 1930s and early 1940s on 40-acre spacing. Waterflooding commenced in 1958. There have been a total of 26 20-acre infill wells drilled on the Unit in four different drilling programs from 1983 to 2007. All four 20-acre infill drilling programs were successful. We have 22 more proved undeveloped locations and multiple unproved 20-acre locations.

Proved Reserves

The following table sets forth a summary of information related to our estimated net proved reserves as of the dates indicated based on reserve reports prepared by LaRoche Petroleum Consultants, Ltd. (“LaRoche”). The estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency. Standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

Table of Contents

The following information represents estimates of our proved reserves as of December 31, 2013, 2012 and 2011. These reserve estimates have been prepared in compliance with the SEC rules and accounting standards using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price for each month in the years ended December 31, 2013, 2012 and 2011. As a result of this methodology, we used an average WTI posted price of $93.42 per Bbl for oil and an average Platts' Henry Hub natural gas price of $3.67 per MMBtu to calculate our estimate of proved reserves as of December 31, 2013. Please see the table below.

	As of December 31,		
	2013	2012	2011
Reserve Data:			
Estimated net proved reserves:			
Oil (MMBbls)	57.0	52.0	38.2
Natural Gas Liquids (MMBbls)	4.1	4.6	4.8
Natural Gas (Bcf)	159.0	159.3	122.6
Total (MMBoe)	87.6	83.2	63.4
Proved developed reserves (MMBoe)	75.9	75.0	55.4
Proved undeveloped reserves (MMBoe)	11.7	8.2	8.0
Proved developed reserves as a percentage of total proved reserves	87 %	90 %	87 %
Standardized measure (in millions)(a)	$1,557.0	$1,425.9	$1,140.4
Oil and Natural Gas Prices(b)			
Oil - WTI per Bbl	$93.42	$91.17	$92.71
Natural gas - Henry Hub per MMBtu	$3.67	$2.76	$4.12

(a) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price) without giving effect to non-property related expenses such as general administrative expenses and debt service or to depletion, depreciation and amortization and discounted using an annual discount rate of 10%. For the purpose of calculating the standardized measure, the costs and prices are unescalated. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on its share of Legacy's taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure. Standardized measure does not give effect to derivative transactions. For a description of our derivative transactions, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operation — Investing Activities.”

(b) Oil and natural gas prices as of each date are based on the unweighted arithmetic average of the first-day-of-the-month price for each month, with these representative prices adjusted by property to arrive at the appropriate net sales price, which is held constant over the economic life of the property.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required for recompletion.

The data in the above table 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. Please read "Risk Factors — Our estimated reserves are based on many assumptions

Table of Contents

that may prove inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.” Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. 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.

From time to time, we engage LaRoche to prepare a reserve and economic evaluation of properties that we are considering purchasing. Neither LaRoche nor any of its employees have any interest in those properties, and the compensation for these engagements is not contingent on their estimates of reserves and future net revenues for the subject properties. During 2013, 2012 and 2011, we paid LaRoche approximately $400,646, $306,861 and $337,372, respectively, for such reserve and economic evaluations as well as its annual reserve report.

Internal Control over Reserve Estimations

Legacy's proved reserves are estimated at the well or unit level and compiled for reporting purposes by Legacy's reservoir engineering staff, none of whom are members of Legacy's operating teams nor are they managed by members of Legacy's operating teams. Legacy maintains internal evaluations of its reserves in a secure engineering database. Legacy's reservoir engineering staff meets with LaRoche periodically throughout the year to discuss assumptions and methods used in the reserve estimation process. Legacy provides LaRoche information on all properties acquired during the year for addition to Legacy’s reserve report. LaRoche updates production data from public sources and then modifies production forecasts for all properties as necessary. Legacy provides to LaRoche lease operating statement data at the property level from Legacy’s accounting system for estimation of each property’s operating expenses, price differentials, gas shrinkage and NGL yield. Legacy's reserve engineering staff provides all changes to Legacy’s ownership interests in the properties to LaRoche for input into the reserve report. Legacy provides information on all capital projects completed during the year as well as changes in the expected timing of future capital projects. Legacy provides updated capital project cost estimates and abandonment cost and salvage value estimates. Legacy's internal engineering staff coordinates with Legacy's accounting and other departments and works closely with LaRoche to ensure the integrity, accuracy and timeliness of data that is furnished to LaRoche for its reserve estimation process. All of the reserve information in Legacy's secure reserve engineering data base is provided to LaRoche. After evaluating and inputting all information provided by Legacy, LaRoche, as independent third-party petroleum engineers, provides Legacy with a preliminary reserve report which Legacy's engineering staff and its Chief Financial Officer review for accuracy and completeness with an emphasis on ownership interest, capital spending and timing, expense estimates and production curves. After considering comments provided by Legacy, LaRoche completes and publishes the final reserve report. Legacy's engineering staff, in coordination with Legacy's accounting department and its Chief Financial Officer, ensure that the information derived from LaRoche's reports is properly disclosed in our filings.

Legacy’s Corporate Planning Manager is the reservoir engineer primarily responsible for overseeing the preparation of reserve estimates by the third-party engineering firm, LaRoche. He has held a wide variety of technical and supervisory positions during a 36-year career with four publicly traded oil and natural gas producing companies, including Legacy. He has over 26 years of SEC reserve report preparation experience in addition to continuing education courses on reserve estimation and reporting, including one in 2009 covering the effect of the SEC’s Final Rule, Modernization of Oil and Gas Reporting. For the professional qualifications of the primary person responsible for the third party reserve evaluation, please see the last paragraph of Exhibit 99.1 - Summary Reserve Report from LaRoche Petroleum Consultants, Ltd.

Table of Contents

Production and Price History

The following table sets forth a summary of unaudited information with respect to our production and sales of oil and natural gas for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012(a)	2011
Production:			
Oil (MBbls)	4,475	3,337	2,951
Natural gas liquids (MGal)	13,272	14,607	14,559
Gas (MMcf)	14,328	10,417	8,842
Total (MBoe)	7,179	5,421	4,771
Average daily production (Boe per day)	19,668	14,811	13,071
Average sales price per unit (excluding commodity derivative cash settlements):			
Oil (per Bbl)	$90.62	$85.78	$89.62
NGL (per Gal)	$1.06	$1.00	$1.30
Gas (per Mcf)	$4.60	$4.38	$6.05
Combined (per Boe)	$67.63	$63.91	$70.61
Average sales price per unit (including commodity derivative cash settlements):			
Oil (per Bbl)	$87.46	$82.72	$85.78
NGL (per Gal)	$1.06	$1.00	$1.30
Gas (per Mcf)	$5.09	$5.93	$7.41
Combined (per Boe)	$66.64	$65.00	$70.74
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$19.89	$19.08	$18.37
Ad valorem taxes	$1.65	$1.76	$1.95
Production and other taxes	$4.11	$3.83	$4.26
General and administrative	$4.03	$4.52	$4.84
Depletion, depreciation and amortization	$22.07	$18.84	$18.48

(a) Reflects the production and operating results of the COG 2012 Acquisition properties from the closing date on December 20, 2012 through December 31, 2012.

Productive Wells

The following table sets forth information at December 31, 2013 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the product of our fractional working interests owned in gross wells.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated	3,198	2,543	536	446	3,734	2,989
Non-operated	3,280	380	1,057	109	4,337	489
Total	6,478	2,923	1,593	555	8,071	3,478

Table of Contents

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2013 relating to our leasehold acreage.

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross(c)	Net(d)	Gross(c)	Net(d)
Total	898,824	369,047	217,299	64,164

(a) Developed acres are acres spaced or assigned to productive wells or wells capable of production.

(b) Undeveloped acres are acres which are not held by commercially producing wells, regardless of whether such acreage contains proved reserves. All of our proved undeveloped locations are located on acreage currently held by production. As the economic viability of any potential oil and natural gas development related to these acres is remote, we have assigned no value to our acreage not held by production and thus the minimum remaining term of the leases is immaterial to us.

(c) 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.

(d) 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 product of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Drilling Activity

The following table sets forth information with respect to wells completed by Legacy during the years ended December 31, 2013, 2012 and 2011. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the numbers of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of oil and natural gas, regardless of whether they produce a reasonable rate of return.

	Year Ended December 31,		
	2013	2012	2011
Gross:			
Development			
Productive	104	57	92
Dry	—	—	—
Total	104	57	92
Exploratory			
Productive	2	3	—
Dry	—	—	—
Total	2	3	—
Net:			
Development			
Productive	28.3	21.4	32.3
Dry	—	—	—

Total	28.3	21.4	32.3
Exploratory			
Productive	0.1	0.15	—
Dry	—	—	—
Total	0.1	0.15	—

Table of Contents

Summary of Development Projects

We are currently pursuing an active development strategy. For the year ended December 31, 2013, we invested approximately $94.0 million in implementing our development strategy, including $63.6 million related to the development of proved undeveloped reserves. We estimate that our capital expenditures for the year ending December 31, 2014 will be approximately $100 million for development drilling, recompletions and fracture stimulation and other development-related projects to implement this strategy. All of these development projects are located in the Permian Basin, Wyoming, North Dakota and the East Binger field in Oklahoma. We will consider adjustments to this capital program based on our assessment of additional development opportunities that are identified during the year and the cash available to invest in our development projects.

Operations

General

We operate approximately 78% of our net daily production of oil and natural gas. 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 drilling rigs or any material oil field services equipment used for drilling or maintaining wells on properties we operate. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ drilling, production, and reservoir engineers, contract geologists and other specialists who have worked and will work to improve production rates, increase reserves, and lower the cost of operating our oil and natural gas properties. We also employ field operating personnel including production superintendents, production foremen, production technicians and lease operators. We charge the non-operating partners an operating fee for operating the wells, typically on a fee per well-operated basis proportionate to each owner's working interest. 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 well drilled on the lease premises. In the Permian Basin, this amount generally ranges from 12.5% to 33.7%, resulting in an 87.5% to 66.3% net revenue interest to us. Most of our leases are held by production and do not require lease rental payments.

Derivative Activity

We enter into derivative transactions with unaffiliated third parties with respect to oil and natural gas prices to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and natural gas prices. We have entered into derivative contracts in the form of fixed price swaps for NYMEX WTI oil, NYMEX Henry Hub natural gas, West Texas Waha natural gas, ANR-Oklahoma natural gas and Rocky Mountain CIG natural gas as well as Midland-to-Cushing crude oil basis differentials. We have also entered into multiple NYMEX WTI oil derivative three-way collar contracts and enhanced swap contracts, as well as NYMEX Henry Hub natural gas three-way collar contracts. We also enter into derivative transactions with respect to LIBOR interest rates to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in LIBOR interest rates. All of our interest rate derivative transactions are LIBOR interest rate swaps. Our derivatives swap floating LIBOR rates for fixed rates. All of these commodity and interest rate contracts were executed in a costless manner, requiring no payment of premiums. Furthermore, all of our current derivative counterparties are current or former members of our bank group. For a more detailed discussion of our derivative activities, please read “Business – Oil and Natural Gas Derivative Activities,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Cash Flow from Operations” and "— Quantitative and Qualitative Disclosures About Market Risk."

Table of Contents

Title to Properties

Prior to completing an acquisition of producing oil and natural gas leases, 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 opinions have been obtained on a portion of our properties.

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title 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 assets. 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 will materially interfere with our use 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 document.

ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

PART II

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

Our units, which were first offered and sold to the public on January 12, 2007, are listed on the NASDAQ Global Select Market under the symbol "LGCY." As of February 20, 2014, there were 57,514,735 units outstanding, held by approximately 107 holders of record, including units held by our Founding Investors.

The following table presents the high and low sales prices for our units during the periods indicated (as reported on the NASDAQ Global Select Market) and the amount of the quarterly cash distributions we paid on each of our units with respect to such periods.

	Price Ranges		Cash Distribution per Unit	Cash Distribution to General Partner	
2013	High	Low			
First Quarter	$27.79	$24.20	$0.575	$10,529	
Second Quarter	$28.70	$24.77	$0.580	$10,620	
Third Quarter	$28.24	$24.62	$0.585	$10,712	
Fourth Quarter	$29.49	$26.29	$0.590	$10,803	(a)
	Price Ranges		Cash Distribution per Unit	Cash Distribution to General Partner	
2012	High	Low			
First Quarter	$30.07	$27.11	$0.555	$10,163	
Second Quarter	$29.48	$23.16	$0.560	$10,254	
Third Quarter	$29.40	$24.90	$0.565	$10,346	
Fourth Quarter	$29.93	$22.33	$0.570	$10,437	

(a) This distribution was paid to our general partner concurrent with our distribution to unitholders on February 14, 2014.

Distribution Policy

Our primary business objective is to generate stable cash flows allowing us to make cash distributions to our unitholders. The aggregate quarterly amount of cash distributions to our unitholders is a distribution of Available Cash as required by our partnership agreement. Under our partnership agreement, Available Cash is defined generally to mean, cash on hand at the end of each quarter, plus working capital borrowings made after the end of the quarter, less cash reserves determined by our general partner, in its sole discretion, to be necessary and appropriate to provide for:

- the conduct of our business (including reserves for future capital expenditures, future debt service requirements and our anticipated capital needs);

- compliance with applicable law or any of our debt instruments or other agreements; and

- future distributions to our unitholders for any of the upcoming four quarters.

We currently pay quarterly cash distributions of $0.59 per unit.

Recent Sales of Unregistered Securities

None.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

You should read the following selected financial data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Legacy's financial statements and related notes included elsewhere in this annual report on Form 10-K. The operating results of the properties acquired have been included from their respective acquisition dates as discussed below.

	Years Ended December 31,				
	2013	2012(a)	2011	2010(b)	2009
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Oil sales	$405,536	$286,254	$264,473	$172,754	$103,319
Natural gas liquids sales	14,095	14,592	18,888	13,670	11,565
Natural gas sales	65,858	45,614	53,524	29,965	22,395
Total revenues	485,489	346,460	336,885	216,389	137,279
Expenses:					
Oil and natural gas production	154,679	112,951	96,914	69,228	48,814
Production and other taxes	29,508	20,778	20,329	12,683	8,145
General and administrative	28,907	24,526	23,084	19,265	15,502
Depletion, depreciation, amortization and accretion	158,415	102,144	88,178	62,894	58,763
Impairment of long-lived assets	85,757	37,066	24,510	13,412	9,207
(Gain) loss on disposal of assets	579	(2,496)	(625)	592	378
Total expenses	457,845	294,969	252,390	178,074	140,809
Operating income (loss)	27,644	51,491	84,495	38,315	(3,530)
Other income (expense):					
Interest income	776	16	15	10	9
Interest expense	(50,089)	(20,260)	(18,566)	(25,766)	(13,222)
Equity in income of partnerships	559	111	138	97	31
Net gains (losses) on commodity derivatives	(13,531)	38,493	6,857	(1,400)	(75,554)
Other	18	(118)	152	90	(11)
Income (loss) before income taxes	(34,623)	69,733	73,091	11,346	(92,277)
Income taxes	(649)	(1,096)	(1,030)	(537)	(554)
Net income (loss) from continuing operations	$(35,272)	$68,637	$72,061	$10,809	$(92,831)
Income (loss) per unit					
Basic and diluted	$(0.62)	$1.40	$1.63	$0.27	$(2.89)
Distributions paid per unit	$2.31	$2.23	$2.14	$2.08	$2.08
Cash Flow Data:					
Net cash provided by operating activities	$241,134	$149,641	$184,237	$101,371	$37,476
Net cash provided by (used in) investing activities	$(209,401)	$(696,279)	$(206,816)	$(285,246)	$23,294
Net cash provided by (used in) financing activities	$(32,658)	$546,996	$22,252	$183,136	$(59,053)
Capital expenditures	$204,911	$704,191	$207,565	$311,277	$22,734

Table of Contents

	Historical As of December 31,				
	2013	2012(a)	2011	2010(b)	2009
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$2,584	$3,509	$3,151	$3,478	$4,217
Other current assets	72,115	84,401	56,634	47,120	45,394
Oil and natural gas properties, net of accumulated depletion, depreciation and amortization	1,535,429	1,571,926	959,329	843,836	575,425
Other assets	49,705	30,163	24,374	14,992	28,457
Total assets	$1,659,833	$1,689,999	$1,043,488	$909,426	$653,493
Current liabilities	$93,890	$103,723	$97,450	$72,955	$54,226
Long term debt	878,693	775,838	337,000	325,000	237,000
Other long-term liabilities	176,854	140,158	120,703	119,732	83,607
Unitholders' equity	510,396	670,280	488,335	391,739	278,660
Total liabilities and unitholders' equity	$1,659,833	$1,689,999	$1,043,488	$909,426	$653,493

(a) Reflects Legacy's purchase of the oil and natural gas properties acquired in the COG 2012 Acquisition as of the date of the acquisition. Consequently, the operations of these acquired properties are only included for the period from the closing date of the acquisition through December 31, 2012 and thereafter.

(b) Reflects Legacy's purchase of the oil and natural gas properties acquired in the Wyoming Acquisition and in the acquisition of certain oil and natural gas properties located primarily in the Permian Basin from a subsidiary of Concho Resources, Inc. ("COG 2010 Acquisition") as of the date of their respective acquisitions. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2010 and thereafter.

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

The following discussion and analysis should be read in conjunction with the "Selected Historical Consolidated Financial Data" and the accompanying financial statements and related notes included elsewhere in this annual report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this report, particularly in "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Information," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, actual results may differ materially from those anticipated or implied in the forward-looking statements.

Overview

Because of our rapid growth through acquisitions and development of properties, historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results. The operating results of the acquisition of certain oil and natural gas properties located primarily in the

Permian Basin from a subsidiary of Concho Resources, Inc (the "COG 2012 Acquisition") have been included since December 20, 2012. During 2013, we consummated $108.4 million of acquisitions, excluding $11.0 million of non-cash asset retirement obligations, consisting of 16 individually immaterial transactions. The operating results of these acquisitions have been included from their respective acquisition dates.

Table of Contents

Trends Affecting Our Business and Operations

Acquisitions have been financed with a combination of proceeds from bank borrowings, issuance of notes, issuances of units and cash flow from operations. Post-acquisition activities are focused on evaluating and exploiting the acquired properties and evaluating potential add-on acquisitions. 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 may fluctuate widely in the future.

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.

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. We attempt to overcome this natural decline by acquiring more reserves than we produce, drilling to find additional reserves, utilizing multiple types of recovery techniques such as secondary (waterflood) and tertiary (CO_2 and nitrogen) recovery methods to re-pressure the reservoir and recover additional oil, recompleting or adding pay in existing wellbores and improving artificial lift. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on adding reserves through acquisitions and development projects. Our ability to add reserves through acquisitions and development projects is dependent upon many factors including our ability to raise capital, obtain regulatory approvals and contract drilling rigs and personnel.

Our revenues are highly sensitive to changes in oil and natural gas prices and to levels of production. As set forth under “Investing Activities,” we have entered into oil, NGL and natural gas derivatives designed to mitigate the effects of price fluctuations covering a significant portion of our expected production, which allows us to mitigate, but not eliminate, oil, NGL and natural gas price risk. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in oil and natural gas prices will affect our ability to execute our capital investment programs and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in oil and natural gas prices may have on the value of our proved reserves and their impact on any redetermination to our borrowing base under our revolving credit facility.

Legacy does not specifically designate derivative instruments as cash flow hedges; therefore, the mark-to-market adjustment reflecting the change in fair value associated with these instruments is recorded in current earnings.

We strive to increase our production levels to maximize our revenue and cash available for distribution. Additionally, we continuously monitor our operations to ensure that we are incurring operating costs at the optimal level. Accordingly, we continuously monitor our production and operating costs per well to determine if any wells or properties should be shut-in or recompleted.

Such costs include, but are not limited to, the cost of electricity to lift produced fluids, chemicals to treat wells, field personnel to monitor the wells, well repair expenses to restore production, well workover expenses intended to increase production and ad valorem taxes. We incur and separately report severance taxes paid to the states and counties in which our properties are located. These taxes are reported as production taxes and are a percentage of oil and natural gas revenue. Ad valorem taxes are a percentage of property valuation. Gathering and transportation costs are generally borne by the purchasers of our oil and natural gas as the price paid for our products reflects these costs. We do not consider royalties paid to mineral owners an expense as we deduct hydrocarbon volumes owned by mineral owners from reported hydrocarbon sales volumes.

41

Table of Contents

Operating Data

The following table sets forth our selected financial and operating data for the periods indicated.

	Year Ended December 31,		
	2013	2012(b)	2011
	(In thousands, except per unit data and production)		
Revenues			
Oil sales	$405,536	$286,254	$264,473
Natural gas liquids sales	14,095	14,592	18,888
Natural gas sales	65,858	45,614	53,524
Total revenues	$485,489	$346,460	$336,885
Expenses:			
Oil and natural gas production	$142,798	$103,409	$87,626
Ad valorem taxes	11,881	9,542	9,288
Total	$154,679	$112,951	$96,914
Production and other taxes	$29,508	$20,778	$20,329
General and administrative excluding LTIP	$24,093	$20,980	$19,063
LTIP expense	4,814	3,546	4,021
Total general and administrative	$28,907	$24,526	$23,084
Depletion, depreciation, amortization and accretion	$158,415	$102,144	$88,178
Commodity derivative cash settlements:			
Oil derivative cash settlements paid	(14,160)	(10,211)	(11,335)
Natural gas derivative cash settlements received	7,104	16,113	11,972
Total commodity derivative cash settlements	(7,056)	5,902	637
Production:			
Oil (MBbls)	4,475	3,337	2,951
Natural gas liquids (MGal)	13,272	14,607	14,559
Natural gas (MMcf)	14,328	10,417	8,842
Total (MBoe)	7,179	5,421	4,771
Average daily production (Boe/d)	19,668	14,811	13,071
Average sales price per unit (excluding commodity derivative cash settlements):			
Oil price (per Bbl)	$90.62	$85.78	$89.62
Natural gas liquids price (per Gal)	$1.06	$1.00	$1.30
Natural gas price (per Mcf)(a)	$4.60	$4.38	$6.05
Combined (per Boe)	$67.63	$63.91	$70.61
Average sales price per unit (including commodity derivative cash settlements):			
Oil price (per Bbl)	$87.46	$82.72	$85.78
Natural gas liquids price (per Gal)	$1.06	$1.00	$1.30
Natural gas price (per Mcf)(a)	$5.09	$5.93	$7.41
Combined (per Boe)	$66.64	$65.00	$70.74
Average WTI oil spot price (per Bbl)	$97.98	$94.05	$94.88
Average Henry Hub natural gas index price (per Mcf)	$3.66	$2.79	$4.04
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$19.89	$19.08	$18.37
Ad valorem taxes	$1.65	$1.76	$1.95
Production and other taxes	$4.11	$3.83	$4.26

General and administrative excluding LTIP	$3.36	$3.87	$4.00
Total general and administrative	$4.03	$4.52	$4.84
Depletion, depreciation, amortization and accretion	$22.07	$18.84	$18.48

(a) We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content contained within those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin and for Legacy as a whole are higher than Henry Hub natural gas index prices due to this NGL content.

(b) Reflects the production and operating results of the oil and natural gas properties acquired in the COG 2012 Acquisition from the closing date of the acquisition through December 31, 2012.

Table of Contents

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Legacy's revenues from the sale of oil were $405.5 million and $286.3 million for the years ended December 31, 2013 and 2012, respectively. Legacy's revenues from the sale of NGLs were $14.1 million and $14.6 million for the years ended December 31, 2013 and 2012, respectively. Legacy's revenues from the sale of natural gas were $65.9 million and $45.6 million for the years ended December 31, 2013 and 2012, respectively. The $119.3 million increase in oil revenue reflects an increase in oil production of 1,138 MBbls (34%) combined with an increase in average realized price of $4.84 per Bbl (6%) to $90.62 for the year ended December 31, 2013 from $85.78 for the year ended December 31, 2012. The increase in production is due primarily to 1,005 MBbls of oil production related to Legacy's purchase of oil and natural gas properties in the COG 2012 Acquisition, and, to a lesser extent, production from our other acquisitions of additional oil and natural gas properties and our development activities that were primarily focused on oil-weighted projects in the Permian Basin. The increase in realized oil price was primarily caused by an increase in the average WTI crude oil price of $3.93, and to a lesser extent, improvements in our crude oil differentials in the Rocky Mountain and Permian Basin regions during the year ended December 31, 2013 compared to the same period in 2012. The $0.5 million decrease in NGL revenues reflects a decrease in NGL production of 1,335 MGal (9%) during 2013, partially offset by an increase in realized NGL price of $0.06 per Gal (6%) to $1.06 per Gal for the year ended December 31, 2013 from $1.00 per Gal for the year ended December 31, 2012. The $20.2 million increase in natural gas revenues reflects an increase in our natural gas production volumes combined with an increase in our realized natural gas prices. Our natural gas production increased by approximately 3,911 MMcf (38%), primarily due to our acquisitions, most notably the COG 2012 Acquisition (4,650 MMcf), as well as our development activities, which were partially offset by third party infrastructure issues that adversely impacted our natural gas production mostly in the Permian Basin during 2013. Average realized gas prices increased by $0.22 per Mcf (5%) to $4.60 per Mcf for the year ended December 31, 2013 from $4.38 per Mcf for the year ended December 31, 2012, as a significant increase in dry natural gas prices was mostly offset by a worsening of differentials primarily due to the curtailment of a portion of our NGL-rich natural gas production in the Permian Basin in 2013.

For the year ended December 31, 2013, Legacy recorded $13.5 million of net losses on oil and natural gas derivatives. Commodity derivative gains and losses represent the changes in fair value of our commodity derivative contracts during the period and are primarily based on oil and natural gas futures prices. The net loss recognized during 2013 was primarily due to increased oil futures prices for 2013 and 2014 and, to a lesser extent, higher natural gas futures prices partially offset by the impact of lower oil futures prices beyond 2014. For the year ended December 31, 2012, Legacy recorded $38.5 million of net gains on oil and natural gas derivatives. Settlements of such contracts resulted in cash payments of $7.1 million and cash receipts of $5.9 million during 2013 and 2012, respectively.

Legacy's oil and natural gas production expenses, excluding ad valorem taxes, increased to $142.8 million ($19.89 per Boe) for the year ended December 31, 2013 from $103.4 million ($19.08 per Boe) for the year ended December 31, 2012. Production expenses increased primarily due to $30.8 million of expenses related to properties acquired in the COG 2012 Acquisition, the acquisition of other oil and natural gas properties and, to a lesser extent, expenses associated with Legacy's development activities. Additionally, production expenses per Boe increased in 2013 compared to 2012 due to industry-wide cost increases and third-party infrastructure issues that negatively impacted our production for the period. Legacy's ad valorem tax expense increased to $11.9 million ($1.65 per Boe) for the year ended December 31, 2013 from $9.5 million ($1.76 per Boe) for the year ended December 31, 2012 due to increased well counts acquired in connection with the COG 2012 Acquisition and the acquisition of additional oil and natural gas properties.

Legacy's production and other taxes were $29.5 million and $20.8 million for the years ended December 31, 2013 and 2012, respectively. Production and other taxes increased because of higher total revenues in 2013, as production and other taxes are assessed as a percentage of revenue and that percentage remained relatively unchanged between 2013 and 2012.

Table of Contents

Legacy's general and administrative expenses were $28.9 million and $24.5 million for the years ended December 31, 2013 and 2012, respectively. General and administrative expenses increased approximately $4.4 million between periods primarily due to $2.9 million of increased salary and benefit expenses, net of overhead recovery, due to the hiring of additional personnel commensurate with the growth of our asset base and $1.3 million of increased unit-based compensation due to an increase in our unit price between December 31, 2012 and December 31, 2013.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $158.4 million and $102.1 million for the years ended December 31, 2013 and 2012, respectively. DD&A increased primarily due to approximately $48.6 million of depletion expense related to the properties acquired in the COG 2012 Acquisition and development activity during the year ended December 31, 2013. Our depletion rate per Boe for the year ended December 31, 2013 was $22.07 compared to $18.84 for the year ended December 31, 2012. This increase is primarily driven by the COG 2012 Acquisition and other recent acquisitions, which have a higher costs basis than our historical assets.

Impairment expense was $85.8 million and $37.1 million for the years ended December 31, 2013 and 2012, respectively. In 2013, Legacy recognized $78.0 million of impairment expense in 98 separate producing fields, due primarily to the decrease in commodity prices primarily related to natural gas differentials during the year ended December 31, 2013, combined with higher lifting costs, which decreased the expected future cash flows below the carrying value of the assets. The remaining $7.8 million was impairment of unproved properties acquired since 2010 that are no longer viable. In 2012, Legacy recognized impairment expense of $22.8 million in 64 separate producing fields due primarily to the decrease in commodity prices during the year ended December 31, 2012 combined with higher lifting costs, which decreased the expected future cash flows below the carrying value of the assets. In 2012, Legacy also recognized $6.5 million of impairment related to the reduction in the carrying value of a property that Legacy entered into an option to sell. Finally, Legacy recognized $7.8 million of impairment of goodwill during 2012 related to a decline in oil futures prices between announcement and closing date of a transaction, as hedging does not impact the associated fair value of properties for purposes of measuring impairment.

Interest expense was $50.1 million and $20.3 million for the years ended December 31, 2013 and 2012, respectively. The increase in interest expense is primarily due to $35.1 million of interest expense related to the issuance of the Senior Notes in December 2012 and May 2013. This increase was partially offset by reduced interest rate expenses related to our interest rate swaps, which decreased by $3.3 million to $1.2 million in 2013 from $4.5 million in 2012. Cash payments on our interest rate swaps were $6.0 million and $7.0 million in 2013 and 2012, respectively.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Legacy's revenues from the sale of oil were $286.3 million and $264.5 million for the years ended December 31, 2012 and 2011, respectively. Legacy's revenues from the sale of NGLs were $14.6 million and $18.9 million for the years ended December 31, 2012 and 2011, respectively. Legacy's revenues from the sale of natural gas were $45.6 million and $53.5 million for the years ended December 31, 2012 and 2011, respectively. The $21.8 million increase in oil revenue reflects an increase in oil production of 386 MBbls (13%) due primarily to acquisitions of producing properties during 2012, including twelve days of production from the COG 2012 Acquisition, and, to a lesser extent, our development activities that were primarily focused on oil-weighted projects in the Permian Basin. These production increases were partially offset by a $3.84 per Bbl (4%) decrease in realized oil sales price from $89.62 for the year ended December 31, 2011, to $85.78 for the year ended December 31, 2012. This decrease in realized oil price was primarily caused by an increased average oil differential of approximately $2.75 per Bbl as well as a lower average price of WTI crude oil. The $4.3 million decrease in NGL revenues reflects a decrease in realized NGL price of $0.30 per Gal (23%) from $1.30 per Gal for the year ended December 31, 2011, to $1.00 per Gal for the year ended December 31, 2012. The $7.9 million decrease in natural gas revenues reflects a $1.67 per Mcf (28%) decrease in natural gas sales price from $6.05 per Mcf for the year ended December 31, 2011 to $4.38 per Mcf for the year ended

December 31, 2012, which primarily reflects a lower weighted average NYMEX Henry Hub index natural gas prices of approximately $1.24 per MMbtu in 2012. We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content contained within those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin and for Legacy as a whole are substantially higher than NYMEX Henry Hub natural gas prices due to this NGL content. Along with lower weighted average NYMEX Henry Hub prices in 2012 compared to 2011, our realized natural gas prices also reflect lower positive differentials in 2012 over NYMEX Henry Hub prices, which reflects the lower average prices of the NGL content in our Permian Basin natural gas production during 2012 compared to 2011. This realized price decline was partially offset by an increase in natural gas production of approximately 1,575 MMcf (18%) due primarily to the full year impact during 2012 of our 2011 acquisitions of producing properties which were natural gas-weighted and, to a lesser extent, twelve days of production from the COG 2012 Acquisition, our other 2012 acquisitions and our development activities. The Wolfberry play, which is our primary focus of development activity in the Permian Basin, produces mostly oil but also a significant amount of NGL-rich casinghead natural gas.

For the year ended December 31, 2012, Legacy recorded $38.5 million of net gains on oil and natural gas derivatives. Commodity derivative gains and losses represent the changes in fair value of our commodity derivative contracts during the period and are primarily based on oil and natural gas futures prices. Accordingly, the net gain recognized during the year ended December 31, 2012 is primarily due to a decrease in oil futures prices and, to a lesser extent, a decrease in natural gas futures prices during the period. For the year ended December 31, 2011, Legacy recorded $6.9 million of net gains on oil and natural gas derivatives. Settlements of such contracts resulted in cash receipts of $5.9 million and $0.6 million during 2012 and 2011, respectively.

Legacy’s oil and natural gas production expenses, excluding ad valorem taxes, increased to $103.4 million ($19.08 per Boe) for the year ended December 31, 2012 from $87.6 million ($18.37 per Boe) for the year ended December 31, 2011. Production expenses increased primarily because of (i) $5.1 million related to increases in workover and other one-time well failure related expenses due to both increases in number of incidents as well as average cost per job, (ii) $0.8 million of increased production expenses for the twelve days of activity related to the COG 2012 Acquisition and (iii) production expenses from other acquisitions. Legacy’s ad valorem tax expense increased to $9.5 million ($1.76 per Boe) for the year ended December 31, 2012 from $9.3 million ($1.95 per Boe) for the year ended December 31, 2011 primarily due to the properties acquired during 2012.

Legacy’s production and other taxes were $20.8 million and $20.3 million for the years ended December 31, 2012 and 2011, respectively. Production and other taxes increased because of higher total revenues in 2013, as production and other taxes are assessed as a percentage of revenue and that percentage remained relatively unchanged between 2012 and 2011.

Legacy’s general and administrative expenses were $24.5 million and $23.1 million for the years ended December 31, 2012 and 2011, respectively. General and administrative expenses increased approximately $1.4 million between periods primarily due to $3.3 million of increased salaries due to the hiring of additional personnel commensurate with the growth of our asset base partially offset by a $1.9 million charge, recognized in the fourth quarter of 2011, related to the termination of a purchase and sale agreement and related due diligence costs, as well as lower unit-based compensation of $0.5 million during 2012 due to decreases in our unit price between December 31, 2011 and December 31, 2012.

Legacy’s depletion, depreciation, amortization and accretion expense, or DD&A, was $102.1 million and $88.2 million for the years ended December 31, 2012 and 2011, respectively, reflecting primarily the increase in production and cost basis related to our recent acquisitions and development activity partially offset by increased reserves related to our development activities and acquisitions during the year ended December 31, 2012 compared to the year ended December 31, 2011. Our depletion rate per Boe for the year ended December 31, 2012 was $18.84 compared to $18.48 for the year ended December 31, 2011.

Impairment expense was $37.1 million and $24.5 million for the years ended December 31, 2012 and 2011, respectively. In 2012, Legacy recognized $22.8 million of impairment expense in 64 separate producing fields, due primarily to the decrease in commodity prices including regional oil differentials during the year ended December 31, 2012, combined with higher lifting costs, which decreased the expected future cash flows below the carrying value of the assets. In addition, Legacy recognized $6.5 million of impairment related to the reduction in the carrying value of a property in which Legacy has entered into an option agreement to sell. The third party exercised this option subsequent to year end, on January 3, 2013. The remaining $7.8 million was impairment

Table of Contents

of goodwill recognized on an acquisition of oil and natural gas properties during 2012 as a result of a purchase and sale agreement Legacy entered into with a third party to acquire certain oil and natural gas properties. As is customary in the industry, the purchase price of the properties was negotiated as of the date of the agreement. During the period between the agreement date and the date of closing the acquisition, oil futures prices declined significantly, thereby reducing the fair value of the properties acquired at the date of close. Since oil derivatives we entered into on the agreement date related to expected production from the acquired properties constitute separate transactions, our derivatives do not affect the associated fair value of the oil and natural gas properties acquired. Because the purchase price exceeded the fair value of the properties acquired at the time of closing in May 2012, goodwill was recognized and subsequently tested for impairment. As a result of this test, all of the goodwill associated with this acquisition was impaired. In 2011, Legacy recognized impairment expense in 70 separate producing fields due primarily to the decrease in natural gas prices during the year ended December 31, 2011 combined with higher lifting costs, which decreased the expected future cash flows below the carrying value of the assets.

Interest expense was $20.3 million and $18.6 million for the years ended December 31, 2012 and 2011, respectively. The increase in interest expense is primarily due to $2.0 million of interest expense related to the issuance of the 2020 Senior Notes (defined below) in December 2012 as well as a higher average debt balance under our revolving credit facility during 2012 compared to 2011. This increase was partially offset by reduced interest rate expenses related to our interest rate swaps, which decreased by $0.9 million to $4.5 million in 2012 from $5.4 million in 2011. Cash settlements on our interest rate swaps were $7.0 million and $7.4 million in 2012 and 2011, respectively.

Non-GAAP Financial Measure

Legacy’s management uses Adjusted EBITDA as a tool to provide additional information and metrics relative to the performance of Legacy’s business. Legacy’s management believes that Adjusted EBITDA is useful to investors because this measure is used by many companies in the industry as a measure of operating and financial performance and is commonly employed by financial analysts and others to evaluate the operating and financial performance of the Partnership from period to period and to compare it with the performance of other publicly traded partnerships within the industry. Adjusted EBITDA may not be comparable to a similarly titled measure of other publicly traded limited partnerships or limited liability companies because all entities may not calculate Adjusted EBITDA in the same manner.

The following presents a reconciliation of “Adjusted EBITDA,” which is a non-GAAP measure, to its nearest comparable GAAP measure. Adjusted EBITDA should not be considered as an alternative to GAAP measures, such as net income, operating income, cash flow from operating activities, or any other GAAP measure of financial performance.

Adjusted EBITDA is defined as net income (loss) plus:

- Interest expense;
- Income taxes;
- Depletion, depreciation, amortization and accretion;
- Impairment of long-lived assets;
- (Gain) loss on sale of partnership investment;
- (Gain) loss on disposal of assets;
- Equity in (income) loss of equity method investees;
- Unit-based compensation expense (benefit) related to LTIP unit awards accounted for under the equity or liability methods;
- Minimum payments received in excess of overriding royalty interest earned;

46

Table of Contents

- Equity in EBITDA of equity method investee;
- Net (gains) losses on commodity derivatives; and
- Net cash settlements received (paid) on commodity derivatives.

The following table presents a reconciliation of Legacy's consolidated net income (loss) to Adjusted EBITDA for the years ended December 31, 2013, 2012 and 2011, respectively.

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Net income (loss)	$(35,272)	$68,637	$72,061
Plus:			
Interest expense	50,089	20,260	18,566
Income tax expense	649	1,096	1,030
Depletion, depreciation, amortization and accretion	158,415	102,144	88,178
Impairment of long-lived assets	85,757	37,066	24,510
(Gain) loss on disposal of assets	579	(2,496)	(625)
Equity in income of equity method investees	(559)	(111)	(138)
Unit-based compensation expense	4,814	3,546	4,021
Minimum payments received in excess of overriding royalty interest earned(a)	1,051	—	—
Equity in EBITDA of equity method investee(b)	727	—	—
Net (gains) losses on commodity derivatives	13,531	(38,493)	(6,857)
Net cash settlements received (paid) on commodity derivatives	(7,056)	5,902	637
Adjusted EBITDA	$272,725	$197,551	$201,383

(a) A portion of minimum payments received in excess of overriding royalties earned under a contractual agreement expiring December 31, 2019. The remaining amount of the minimum payments are recognized in net income.

(b) EBITDA applicable to equity method investee is defined as the equity method investee's net income plus interest expense and depreciation.

For the year ended December 31, 2013, Adjusted EBITDA increased 38% to $272.7 million from $197.6 million for the year ended December 31, 2012. This increase is due primarily to increased production from the COG 2012 Acquisition, other acquisitions and development activities, as well as higher realized commodity prices. This increase was partially offset by higher commodity derivative settlement payments of approximately $13.0 million as well as higher expenses and taxes. For the year ended December 31, 2012, Adjusted EBITDA decreased 2% to $197.6 million from $201.4 million for the year ended December 31, 2011. This decrease is due primarily to higher expenses, including increases in production expenses, production taxes and general and administrative expenses that totaled $17.9 million during 2012. This increase was partially offset by Legacy's $9.6 million increase in revenues and an increase in cash receipts on commodity derivatives of $5.3 million during 2012 compared to 2011.

Capital Resources and Liquidity

Legacy's primary sources of capital and liquidity have been cash flow from operations, the issuance of notes, the issuance of additional units, proceeds from bank borrowings or a combination thereof. To date, Legacy's primary use of capital has been for the acquisition and development of oil and natural gas properties and the repayment of bank borrowings.

As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in growing reserves and production will be highly dependent on capital resources available to us and our success in acquiring and developing additional hydrocarbon reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our revolving credit facility, if available, or obtain additional debt or equity financing. Our revolving credit facility and our Senior Notes limit our ability to issue additional debt, but permit us to issue limited amounts of unsecured senior or senior subordinated notes. Further, our existing revolving credit facility matures on March 10, 2016.

Our commodity derivatives position, which we use to mitigate commodity price volatility and support our borrowing capacity, resulted in $7.1 million of cash payments in the year ended December 31, 2013. Based upon current oil and natural gas price expectations and our extensive commodity derivatives positions, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility, under which $451.9 million was available for borrowings as of December 31, 2013, will provide us sufficient working capital to meet our planned capital expenditures of $100 million and planned annualized cash distributions of $135.7 million, which reflect the $33.9 million of distributions attributable to the fourth quarter of 2013 that were paid in the first quarter of 2014. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or planned annualized cash distributions. 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 rate of $0.59 per unit. Please read "— Financing Activities — Our Revolving Credit Facility."

Cash Flow from Operations

Legacy's net cash provided by operating activities was $241.1 million and $149.6 million for the years ended December 31, 2013 and 2012, respectively, with the 2013 period being favorably impacted by higher production volumes primarily related to acquisitions, most notably the COG 2012 Acquistion, and higher realized commodity prices, partially offset by higher expenses.

Legacy's net cash provided by operating activities was $149.6 million and $184.2 million for the years ended December 31, 2012 and 2011, respectively, with the 2012 period being unfavorably impacted by lower realized oil and natural gas prices and higher expenses, partially offset by higher sales volumes.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, NGL and natural gas prices. Oil, NGL and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through acquisitions and development projects, as well as the prices of oil, NGLs and natural gas.

Investing Activities

Legacy's cash capital expenditures were $202.4 million for the year ended December 31, 2013. The total includes $108.4 million related to 16 individually immaterial acquisitions and $94.0 million of development projects.

Legacy's cash capital expenditures were $702.9 million for the year ended December 31, 2012. The total includes $634.8 million related to the COG 2012 Acquisition and 19 individually immaterial acquisitions and $68.2 million of development projects.

We currently anticipate that our development capital budget, which predominantly consists of drilling, recompletion and well stimulation projects, will be $100 million for the year ending December 31, 2014. Our borrowing capacity under our revolving credit facility is $425.9 million as of February 20, 2014. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. We may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, non-operated capital requirements and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner as well as other regulatory matters.

Table of Contents

We enter into oil and natural gas derivatives to reduce the impact of oil and natural gas price volatility on our operations. At February 20, 2014, we had in place oil, natural gas and price differential derivatives covering significant portions of our estimated 2014 through 2018 oil and natural gas production.

By reducing the cash flow effects of price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are major, creditworthy institutions deemed by management as competent and competitive market makers. In addition, all of our current counterparties are current or former lenders under our revolving credit facility, which allows us to avoid margin calls. However, we cannot be assured that all of our counterparties will meet their obligations under our derivative contracts. Due to this uncertainty, we routinely monitor the creditworthiness of our counterparties.

The following tables summarize, for the periods indicated, our oil and natural gas derivatives in place as of February 20, 2014 covering the period from January 1, 2014 through December 31, 2018. We use derivatives, including swaps, enhanced swaps and three-way collars, as our mechanism for offsetting the cash flow effects of changes in commodity prices whereby we pay the counterparty floating prices and receive fixed prices from the counterparty, which serves to reduce the effects on cash flow of the floating prices we are paid by purchasers of our oil and natural gas. These transactions are mostly settled based upon the monthly average closing price of front-month NYMEX WTI oil, the price on the last trading day of front-month NYMEX Henry Hub natural gas and published West Texas Waha, ANR-Oklahoma and Rocky Mountain CIG prices of natural gas.

Oil Swaps:

Calendar Year	Average Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl		
2014	3,087,144	$93.52	$87.50	-	$103.75
2015	545,351	$91.98	$88.50	-	$100.20
2016	228,600	$87.94	$86.30	-	$99.85
2017	182,500	$84.75	$84.75		

Natural Gas Swaps:

Calendar Year	Annual Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu		
2014	8,271,254	$4.32	$3.61	-	$6.47
2015	4,699,300	$4.58	$4.15	-	$5.82
2016	1,419,200	$4.30	$4.12	-	$5.30

We have entered into regional crude oil differential swap contracts in which we have swapped the floating WTI-ARGUS (Midland) crude oil price for floating WTI-ARGUS (Cushing) less a fixed-price differential. As noted above, we receive a discount to the NYMEX WTI crude oil price at the point of sale. Due to refinery downtimes and limited takeaway capacity that has impacted the Permian Basin, the difference between the WTI-ARGUS (Midland) price, which is the price we receive on almost all of our Permian crude oil production, and the WTI-ARGUS (Cushing) price reached historic highs in late 2012 and early 2013. We entered into these differential swaps to negate a portion of this volatility. The following table summarizes the oil differential swap contracts currently in place as of February 20, 2014:

Time Period	Price Range per Bbl

	Average Volumes (Bbls)	Average Price per Bbl	
Q1 2014	132,000	$(1.75)	$(1.75)

We have also entered into multiple NYMEX West Texas Intermediate crude oil derivative three-way collar contracts. Each contract combines a long put, a short put and a short call. The use of the short put allows us to buy a put and sell a call at higher prices, thus establishing a higher ceiling and limiting our exposure to future settlement

Table of Contents

payments while also restricting our downside risk. If the market price is below the long put fixed price but above the short put fixed price, a three-way collar allows us to settle for the long put fixed price. A three-way collar also allows us to settle for WTI market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. The following table summarizes the three-way oil collar contracts currently in place as of February 20, 2014:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2014	780,500	$71.78	$96.78	$110.53
2015				