LEGACY RESERVES LP
Form 10-K
February 27, 2015

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, 2014

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	16-1751069
(State or other jurisdiction of incorporation or organization)	(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.
8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units representing preferred limited partner interests on the NASDAQ Stock Market LLC.
8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units representing preferred limited partner interests 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 $1.5 billion on June 30, 2014, based on $31.24 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

69,208,533 units representing limited partner interests in the registrant were outstanding as of February 23, 2015.

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrant's 2015 annual meeting of unitholders are incorporated by reference into Part III of this annual report on Form 10-K.

LEGACY RESERVES LP

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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.

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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

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gas prices in past 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.

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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 limited partners;
- 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.

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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. References to "units" refers to our units representing limited partner interests in the Partnership and not to the Series A Preferred Units (as defined herein), the Series B Preferred Units (as defined herein) or the Incentive Distribution Units (as defined herein), and "unitholders" refers to the holders of units. As used herein, unless the context requires otherwise, the term "limited partner interests" refers to the units, the Series A Preferred Units, the Series B Preferred Units and the Incentive Distribution Units, collectively, and “limited partners” refers to the holders of limited partner interests. References to "Preferred Units" refer to the Series A Preferred Units and the Series B Preferred Units, collectively.

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, Rocky Mountain and Mid-Continent 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, 2014 are as follows:

- we had proved reserves of approximately 139.0 MMBoe, of which 50% were oil and natural gas liquids (“NGLs”) and 89% were classified as proved developed producing, 2% were proved developed non-producing, and 9% were proved undeveloped; and

- our proved reserves to production ratio was approximately 11.6 years based on the annualized production volumes for the three months ended December 31, 2014.

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 2014, we completed 136 acquisitions of oil and natural gas properties for a total of approximately $2.1 billion. These acquisitions of primarily long-lived, oil and natural gas 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.

2015 Operating Focus

Oil and natural gas prices have recently fallen dramatically and the state of the financial and capital markets for oil and gas exploration and production companies has correspondingly become more challenged.

In response, we have elected to significantly reduce our capital expenditures and drilling activity in 2015. Our capital program is expected to be approximately $30 million in 2015, compared to approximately $133.4 million in 2014. In addition, under the current market prices for oil and natural gas, we may not be able to sustain our current distribution levels to our unitholders.

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Our goals in 2015 are to fund our operations, capital expenditures, interest payments and distributions to limited partners from our internally generated cash flow and to preserve financial flexibility and liquidity to maintain our assets and operations in anticipation of future improvement in the overall economic environment, commodity prices and financial markets.

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 2014 constituted approximately 23% of our $536.3 million of total acquisitions during the year.

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 and our acquisition of non-operated oil and natural gas properties in Colorado in June 2014. The North Dakota properties produce primarily from the Madison and Bakken formations, while the Montana properties produce mostly from the Sawtooth and Bowes formations. The Colorado properties produce primarily from the Williams Fork formation.

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 4.8 MMBoe, are 72% liquids and comprise approximately 52% 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 3.8 MMBoe of proved reserves that are 69% liquids and comprise approximately 41% of our proved reserves in the region. Our remaining properties in the Mid-Continent region are located in multiple counties in Oklahoma, Texas and Arkansas.

Our proved reserves by area are as follows:

Proved Reserves by Operating Region as of December 31, 2014

Operating Regions	Oil (MBbls)	Natural Gas (MMcf)		NGLs(MBbls)	Total (MBoe)	% Liquids	% PDP	% Total
Permian Basin	43,425	143,118	(a)	1,920	69,198	65.5 %	80.0 %	49.8 %
Rocky Mountain	10,252	254,358		6,918	59,563	28.8 %	99.0 %	42.9 %
Mid-Continent	3,163	17,483		3,200	9,277	68.6 %	97.9 %	6.7 %
Other	84	3,017		335	921	45.5 %	100.0 %	0.6 %

Total	56,924	417,976	12,373	138,959	49.9 %	89.5 %	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.

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Acquisition Activities

During the year ended December 31, 2014, we completed 7 acquisitions of oil and natural gas properties with an aggregate purchase price of approximately $536.3 million, excluding $50.5 million of non-cash asset retirement obligations, that added approximately 64.2 MMBoe of proved reserves as of year end.

WPX Acquisition. On June 4, 2014, we purchased a non-operated interest in oil and natural gas properties located in the Piceance Basin in Garfield County, Colorado from WPX Energy Rocky Mountain, LLC, a subsidiary of WPX Energy, Inc., for a net purchase price of $360.0 million (the "WPX Acquisition"). The purchase price was financed partially with net proceeds from Legacy's May 2014 private offering of 6.625% senior unsecured notes due 2021 as well as the issuance of 300,000 Incentive Distribution Units representing limited partner interests in the Partnership (the "Incentive Distribution Units"), 100,000 of which vested immediately and the remainder of which are available to vest and also subject to forfeiture pursuant to the terms of a related Incentive Distribution Unitholder Agreement. The operating results from the WPX Acquisition properties are included in the financial statements to this Form 10-K from the date of the acquisition.

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 nitrogen and CO2) recovery projects.

As of December 31, 2014, we identified 189 gross (127.7 net) proved undeveloped ("PUD") drilling locations, 153 of which were identified and economically viable at December 31, 2013. The table below details the activity in our PUD locations from December 31, 2013 to December 31, 2014:

	Gross Locations	Net Locations	Net Volume (MBoe)
Balance, December 31, 2013	254	168.9	11,665
PUDs converted to PDP by drilling	(42)	(24.3)	(2,538)
PUDs removed due to performance (a)	(18)	(8.0)	(521)
PUDs removed from future drilling schedule (b)	(41)	(34.6)	(1,334)
Acquisition activity	3	3.0	3,005
Additions due to performance (a)	33	22.5	2,656
Other	—	0.2	(383)
Balance, December 31, 2014	189	127.7	12,550

(a) PUDs removed or added due to performance are those PUDs removed or added, as applicable, due to new or revised engineering, geologic and economic evaluations such as offset well production data, the drilling of offset wells, new geologic data or changes in projected capital costs or product prices. PUDs are removed or added depending on whether the technical criteria for the proved undeveloped reserve classification is satisfied and, in the case of additions due to performance, whether the well is scheduled to be drilled within five years after initial recognition as proved reserves.

The increases in PUDs due to performance were primarily driven by offset drilling in connection with our drilling program in the Permian Basin, which includes both the Wolfberry and Horizontal Bone Springs wells and, to a lesser extent, newly-added locations from engineering analysis of results from third-party operators of offset or adjacent wells.

The reductions in PUDs due to performance were primarily due to the removal of PUDs as they became uneconomic as of December 31, 2014 based on commodity price declines or offset well performance.

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(b) 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, 2014, we identified 65 gross (37.5 net) recompletion and fracture stimulation projects.

Excluding acquisitions, we expect to make capital expenditures of approximately $30 million during the year ending December 31, 2015.

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, 2014, we had in place oil and natural gas derivatives covering significant portions of our estimated 2015 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, Rocky Mountain CIG, Northwest Pipeline, NGPL Midcon, California SoCal NGI and San Juan Basin natural gas; and fixed price swaps for the Midland-to-Cushing oil differential.

Marketing and Major Purchasers

For the years ended December 31, 2014, 2013 and 2012, Legacy sold oil, NGL and natural gas production representing 10% or more of total revenues to purchasers as detailed in the table below:

	2014		2013		2012	
Enterprise (Teppco) Crude Oil, LP	12	%	17	%	12	%
Plains Marketing, LP	10	%	7	%	10	%

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.

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.

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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

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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 and localities 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. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. For example, portions of our properties in New Mexico and west Texas are enrolled in Habitat Conservation Plans and as a result we are subject to certain practices and restrictions designed to protect the habitat of the Lesser Prairie Chicken. We believe that we are in substantial compliance with the ESA and the practices and restrictions related to the Lesser Prairie Chicken should not result in material costs or constraints to our operations. 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

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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, 2014. Additionally, as of the date of this document, we are not aware of any environmental issues or claims that require material capital expenditures during 2015. 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.

Activities on Federal Lands. Oil and natural gas exploitation and production activities on federal lands are subject to the National Environmental Policy Act, as amended, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will typically prepare an Environmental Assessment to assess 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. Our current production activities, as well as proposed development plans, on federal lands require governmental permits or similar authorizations that are subject to the requirements of NEPA. This process has the potential to delay, limit or increase the cost of developing oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

Federal, State or Native American Leases. Our operations on federal, state, or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, or BLM, and other agencies. For example, the BLM published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require

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public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface.

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.

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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, 2014, we had 300 full-time employees, including 23 petroleum engineers, 15 accountants, 2 geologists and 13 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 69,529 square feet of office space in Midland, Texas at 303 W. Wall Street, where our principal offices are located. The lease for our Midland office expires in September 2020. 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 most recent 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 most recent 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 most recent 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, future cash distributions on our Preferred Units and future cash distributions to our unitholders. Further, our debt agreements

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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 limited partners.

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 limited partners.

Our future growth may be limited because we distribute all of our available cash to our limited partners, 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 limited partners, 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 or the oil and natural gas industry, 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.

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Further, any delay in the decrease of the cost of rigs and oil field services related to falling oil and natural gas prices may reduce our operating income as a percentage of total revenues during such periods and therefore reduce cash available for distribution to our limited partners.

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

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

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

Historically, oil and natural gas prices have been extremely volatile. For example, for the five years ended December 31, 2014, the NYMEX-WTI oil price ranged from a high of $113.39 per Bbl to a low of $34.03 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $8.15 per MMBtu to a low of $1.82 per MMBtu. As of February 17, 2015, the NYMEX WTI oil spot price was $53.56 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.75 per MMBtu. If oil and natural gas prices decline further or remain at current levels for a prolonged period, it may cause us to reduce or cease paying the distributions we pay to our limited partners.

If commodity prices decline further or remain at current levels 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 limited partners.

Lower oil and natural gas prices may not only decrease our revenues, but also may render many of our development and production projects uneconomical and result in a downward adjustment of our reserve estimates, which would negatively impact our borrowing base under our revolving credit facility and ability to fund operations. As a result, we may reduce the amount of distributions paid to our limited partners or cease paying distributions.

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NYMEX-WTI oil prices have declined from $98.17 per Bbl on December 31, 2013 to $53.45 per Bbl on December 31, 2014. The reduction in price has been caused by many factors, including substantial increases in U.S. production and reserves from unconventional (shale) reservoirs, without a corresponding increase in demand. The International Energy Agency ("IEA") forecasts continued U.S. oil production growth and a slowdown in global demand growth in 2015. This environment could cause the prices for oil to remain at current levels or to fall to lower levels.

Furthermore, the recent decrease in oil and natural gas prices has rendered a significant portion of our development projects uneconomic. In addition, if oil and natural gas prices continue to remain depressed, our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. For example, in the year ended December 31, 2014 we incurred impairment charges of $448.7 million, of which $448.2 million was driven by commodity price changes. 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 limited partners.

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, which may adversely impact our revenues and ability to pay distributions to our limited partners. 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.

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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 $7.68 per Bbl to $82.94 per barrel for the year ended December 31, 2014 from $90.62 per barrel for the year ended December 31, 2013. This decrease in realized oil prices was caused by a larger average oil differential of $2.64 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 2014 compared to 2013. If the current significant differentials continue, they 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 Colorado, 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, CIG-Rockies, Northwest Pipeline, NGPL Midcon, California SoCal NGI and San Juan Basin natural gas prices. While we are paid a local price indexed to or closely related to these indexes, 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 limited partners.

We depend on our revolving credit facility for future capital needs. Our revolving credit facility, which matures on April 1, 2019, limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. As of February 23, 2015, our borrowing base was $700 million and we had approximately $569.9 million available for borrowing.

Our revolving credit facility restricts, among other things, our ability to incur debt and pay distributions to our limited partners, 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 $550 million 6.625%

senior unsecured notes maturing on December 1, 2021 (collectively, the "Senior Notes"), to be immediately due and payable.

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We are prohibited from borrowing under our revolving credit facility to pay distributions to limited partners 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 limited partners 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. Further, if commodity prices materially decrease and result in a decreased value of our oil and natural gas properties, then the borrowing base of our revolving credit facility could be reduced materially.

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 limited partners.

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 or 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.

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

As of February 23, 2015, we had total long-term debt of approximately $980 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 limited partners; 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 and cash flows 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 limited partners.

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. For example, the unweighted average prices used in connection with our reserve report as of December 31, 2014 were $91.48 per Bbl for oil and $4.35 per Mcf for gas. As of February 17, 2015, the NYMEX WTI oil spot price was $53.56 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.75 per Mcf. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance

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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.

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 limited partners.

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 limited partners.

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 limited partners.

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.

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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 limited partners.

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 limited partners.

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 limited partners.

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 and Preferred 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

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cause a corresponding decline in demand for equity investments, in particular for yield-based equity investments such as our units or Preferred Units. Any reduction in demand for our units resulting from other more attractive investment opportunities may cause the trading price of our units or Preferred Units to decline.

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 limited partners.

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 assets and 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

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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 limited partners.

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, industry 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 limited partners.

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 limited partners.

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 limited partners could lose confidence in our financial reporting, which would harm our business and the trading price of our units or Preferred 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.

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A failure in our operational systems or cyber security attacks on any of our facilities or those of third parties may have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our limited partners.

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

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

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 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 limited partners.

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 limited partners.

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 limited partners could be

adversely affected.

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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 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 limited partners.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") 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 falling within classes of swaps designated or to be designated by the CFTC are or will be subject to clearing on a derivative clearing organization ("DCO"). To date, the CFTC has designated only six classes of interest rate and index credit default swaps for mandatory clearing. Transactions in swaps accepted for clearing are subject to execution on a swap trading facility if made available for trading on such 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 otherwise would have to be cleared, 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 the swaps we clear on a DCO. Moreover, as required by the Act, the CFTC and federal financial institution regulators have proposed for adoption regulations imposing margin requirements for uncleared swaps, although the rules as currently proposed would not require non-financial end users of swaps to post such margin in connection with their uncleared swaps. If we were to be required to post margin in the form of cash collateral with respect to our cleared or uncleared swaps, our liquidity could be adversely affected, thereby reducing our ability to use our cash for capital expenditures, distributions to limited partners or other partnership purposes. A requirement to post margin, especially in the form of cash collateral, with respect to any swaps we enter could reduce our ability to execute strategic hedges to reduce

commodity price uncertainty and, thus, to protect our cash flows. However, even if the margin rules adopted do not require us to post any margin or only immaterial amounts of margin,

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any regulated financial institution that we enter into swaps with could contractually require us to post collateral to reduce the amount of capital they must maintain relating to those swaps under new bank capital requirements or pass along their increased capital costs to us, thus increasing our costs of engaging in hedging transactions, decreasing the benefits of those transactions to us and reducing our cash flows and liquidity. We currently hedge primarily 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.

The Act requires the CFTC to adopt limits on the positions that a party may hold in certain contracts relating to physical commodities. The CFTC has proposed new rules that set limits on the positions, other than bona fide hedging positions, that a party may hold in specified core futures relating to certain physical commodities, including NYMEX contracts relating to WTI crude oil and Henry Hub natural gas, as well as options and swaps economically equivalent to such futures contracts, other swaps and options, basis, and commodity index contracts linked to such futures contracts or such physical commodities. 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 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 limited partners 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 limited partners. 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 limited partners.

The European Market Infrastructure Regulation (EMIR), which became effective in 2012, includes regulations related to the trading, reporting and clearing of derivatives subject to EMIR. We have counterparties that are located in a jurisdiction subject to EMIR. Our efforts to comply with EMIR, and EMIR's effect on the derivatives markets and their participants, creates similar risks and could have similar adverse impacts as those under the provisions of Title VII of the Act and the CFTC's swap regulations.

Federal, state and local 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

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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, the produced water from hydraulic fracturing must be disposed of properly, often in salt water disposal wells. Recently, certain groups have expressed concern that seismic activity could be tied to salt water disposal. In response to such concern, the Texas Railroad Commission has adopted regulations which place additional restrictions on the permitting of disposal well operations in areas of historical or future seismic activity. 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 15% 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.

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.

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Risks Related to our Preferred Units

Our Series A Preferred Units and Series B Preferred Units rank senior in right of payment to our units, and we are unable to make any distribution to our unitholders unless full cumulative distributions are made on our Series A Preferred Units and Series B Preferred Units.

We have issued 2,300,000 of our 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units"). We have also issued 7,200,000 of our 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units"). The Series A Preferred Units and Series B Preferred Units (collectively, the "Preferred Units") represent perpetual equity interests in us and rank senior in right of payment to our units. Distributions on the Preferred Units are cumulative from the date of original issue and are payable monthly on the 15th day of each month. No distribution may be declared or paid or set apart for payment on the units, or any other junior securities, unless full cumulative distributions have been or contemporaneously are being paid or provided for on all outstanding Preferred Units and any parity securities through the most recent respective distribution payment dates.

The Preferred Units are subordinated to our existing and future debt obligations, and could be diluted by the issuance of additional partnership securities, including additional preferred units, and by other transactions.

The Preferred Units are subordinated to all of our existing and future indebtedness (including indebtedness outstanding under our Current Credit Agreement, our 8% Senior Notes due 2020 and our 6.625% Senior Notes due 2021). We may incur additional debt under our Current Credit Agreement or future credit facilities or by issuing additional senior or subordinated debt securities. The payment of principal and interest on our debt reduces cash available for distribution to limited partners, including the holders of Preferred Units.

The issuance of additional partnership securities pari passu with or senior to the Preferred Units would dilute the interests of the holders of the Preferred Units, and any issuance of senior securities or parity securities or additional indebtedness could affect our ability to pay distributions on, redeem or pay the liquidation preference on the Preferred Units. Only the change of control provision relating to the Preferred Units protects the holders of the Preferred Units in the event of a highly leveraged or other transaction, including a merger or the sale, lease or conveyance of all or substantially all our assets or business, which might adversely affect the holders of the Preferred Units.

Risks Related to Our Limited Partnership Structure

Our Founding Investors, including members of our management, own an approximately 15% 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 limited partners.

Our Founding Investors, including members of our management, own an approximately 15% limited partner interest in us through the ownership of units 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 limited partners, 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 limited partners, 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 limited partners. 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;

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- 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 limited partners;
- our Founding Investors and their affiliates (other than our executive officers and their affiliates) may engage in competition with us;
- 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 limited partners for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of purchasing limited partner interests, limited partners 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 limited partners;
- 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 limited partners;
- 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 limited partners owning 20% or more of any class of limited partner interests.

Limited partners' voting rights are further restricted by the partnership agreement provision providing that any limited partner interests held by a person that owns 20% or more of any class of limited partner interest then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such limited partner interest 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 limited partners to call meetings or to acquire information about our operations, as well as other provisions limiting the limited partners' ability to influence the manner or direction of management.

Our Founding Investors and their affiliates (other than our general partner and 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.

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

Prior to making any distribution on our outstanding limited partner interests, 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 limited partners.

Our partnership agreement limits our general partner's fiduciary duties to our limited partners and restricts the remedies available to limited partners 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 limited partner;
- provides that our general partner will not have any liability to us or our limited partners 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 limited partners 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 limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that 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 partnership interest 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 partnership interests and may not receive distributions in kind upon our liquidation.

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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 limited partners' proportionate ownership interests in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- 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.

Our general partner may elect to cause us to issue units in connection with a resetting of incentive distribution levels without the approval of our limited partners. Our Incentive Distribution Units may be converted to units in certain circumstances. Any such election or conversion may result in lower distributions to our limited partners in certain situations.

Our general partner has the right, at any time when the partnership has paid distributions of at least $0.7375 for each of the prior four consecutive fiscal quarters and the amount of all distributions during each quarter within such four-quarter period did not exceed the adjusted operating surplus for each such quarter, to reset the initial target distribution levels at higher levels based on our cash distribution levels at the time of the exercise of the reset election.

We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per unit, taking into account the existing levels of incentive distribution payments being made to the holders of Incentive Distribution Units. It is possible that our general partner exercises this reset right at a time when we are experiencing declines in our aggregate cash distributions or at a time when the holders of the Incentive Distribution Units expect that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, the holders of the Incentive Distribution Units may be experiencing, or may expect to experience, declines in the cash distributions it receives related to the Incentive Distribution Units and may therefore desire to be issued our units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for them to own in lieu of the right to receive incentive distribution payments based on increased target distribution levels that are less certain to be achieved. As a result, a reset election may cause our unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new units to the holders of the Incentive Distribution Units in connection with resetting the target distribution levels.

Further, our general partner and Incentive Distribution Unitholders may cause vested and outstanding Incentive Distribution Units to convert to units in certain other circumstances. Any such conversion may cause our unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new units to the holders of the Incentive Distribution Units in connection with any such conversion.

The liability of our limited partners may not be limited if a court finds that limited partner 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

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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 limited partners could, however, be liable for any and all of our obligations as if our limited partners 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 limited partners' right to act with other limited partners to take other actions under our partnership agreement constitutes "control" of our business.

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

Under certain circumstances, limited partners 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 limited partners 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 and Preferred 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 limited partners would be substantially reduced.

The anticipated after-tax economic benefit of an investment in us 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 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 limited partners who are treated as holders of corporate stock would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our limited partners. Because a tax would be imposed upon us as a corporation, our cash available to pay distributions to our limited partners 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 limited partners likely causing a substantial reduction in the value of our limited partner interests.

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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 limited partners would be reduced.

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

The tax treatment of publicly traded partnerships or an investment in our limited partner interests 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 limited partner interests may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time the Obama Administration and members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that would adversely affect publicly traded partnerships. One such Obama Administration budget proposal for fiscal year 2016 would, if enacted, tax publicly traded partnerships with “fossil fuels” activities as corporations for U.S. federal income tax purposes beginning in 2021. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our limited partner interests.

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

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 the current and 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

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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.

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 limited partner interests 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 limited partners and thus will be borne indirectly by our limited partners.

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.

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

Because a limited partner whose limited partner interests are loaned to a "short seller" to cover a short sale of limited partner interests may be considered as having disposed of the loaned limited partner interests, he may no longer be treated for tax purposes as a partner with respect to those limited partner interests during the period of the loan to the short seller and the limited partner 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 limited partner interests may not be reportable by the limited partner and any cash distributions received by the limited partner as to those limited partner interests could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a limited partner where our limited partner interests are loaned to a short seller to cover a short sale of our limited partner interests; therefore, limited partners 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 limited partner interests.

Our limited partners 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 limited partner interests.

In addition to U.S. federal income taxes, our limited partners 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 limited partners 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 limited partners may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may do business or own assets in additional states or foreign countries that impose a personal income tax or an entity level tax. It is the responsibility of each limited partner to file all United States federal, foreign, state and local tax returns that may be required of such limited partner. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our limited partner interests.

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

limited partners, which would result in us filing two tax returns (and our limited partners 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 limited partner 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

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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 limited partners for the year notwithstanding two partnership tax years.

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

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

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

Treatment of distributions on our preferred units as guaranteed payments for the use of capital creates a different tax treatment for the holders of our preferred units than the holders of our units.

The tax treatment of distributions on our preferred units is uncertain. We will treat the holders of our preferred units as partners for tax purposes and will treat distributions on the preferred units as guaranteed payments for the use of capital that will generally be taxable to the holders of our preferred units as ordinary income. Although a holder of our preferred units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, we anticipate accruing and making the guaranteed payment distributions monthly. Otherwise, the holders of our preferred units are generally not anticipated to share in our items of income, gain, loss or deduction. Nor will we allocate any share of our nonrecourse liabilities to the holders of our preferred units. If the preferred units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of the preferred units.

A holder of our preferred units will be required to recognize gain or loss on a sale of units equal to the difference between such holder's amount realized and tax basis in the preferred units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such preferred units. Subject, in certain circumstances, to rules requiring a blended basis among multiple partnership interests, the tax basis of a preferred unit will generally be equal to the sum of the cash and the fair market value of other property paid by the holder of the preferred unit to acquire such preferred unit. Gain or loss recognized by a holder of our preferred units on the sale or exchange of a preferred unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of our preferred units will not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Investment in our preferred units by tax-exempt investors, such as employee benefit plans and individual retirement accounts, and non-U.S. persons raises issues unique to them. Distributions to non-U.S. holders of our preferred units will be treated as "effectively connected income" (which will subject such holders to U.S. net income taxation and possibly the branch profits tax) and will be subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. holders. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders may be required to file U.S. federal income tax returns in order to seek a refund of such excess. The treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain. Holders of our preferred units who are tax-exempt entities or non-U.S. persons should consult their tax advisor with respect to the

tax consequences of owning our preferred units.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

As of December 31, 2014 we owned interests in producing oil and natural gas properties in 665 fields in the Permian Basin, Texas Panhandle, Wyoming, North Dakota, Montana, the Piceance Basin of Colorado, Oklahoma and several other states, from 11,121 gross productive wells of which 3,919 are operated and 7,202 are non-operated. The following table sets forth information about our proved oil and natural gas reserves as of December 31, 2014. 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, 2014 Proved Reserves			Standardized Measure	
Field or Region	MMBoe	R/P (a)	% Oil and NGLs	Amount (b)	% of Total
				($ in Millions)	
Piceance Basin (c)	49.6	12.2	15 %	$313.4	17.9 %
Spraberry/War San	10.6	10.6	67	184.5	10.5
Texas Panhandle	4.8	12.2	72	69.1	3.9
East Binger	3.8	14.9	69	57.2	3.3
Jordan	2.4	13.4	93	44.7	2.6
Caprock	4.6	20.5	100	41.6	2.4
Lea	1.9	14.9	73	41.2	2.3
New Mexico Lower Abo	1.7	5.6	57	38.9	2.2
Deep Rock	1.7	14.4	97	38.0	2.2
Jalmat	2.0	18.3	93	34.0	1.9
Total — Top 10	83.1	12.3	40 %	$862.6	49.2 %
All others	55.9	10.7	65	892.0	50.8
Total	139.0	11.6	50 %	$1,754.6	100.0 %

(a) Reserves as of December 31, 2014 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.

(c) As the Piceance Basin contains 49.6 MMBoe, or 35.7% of total proved reserves of 139.0 MMBoe, the following table presents the production, by product, for the Piceance Basin for the current fiscal year. As we acquired our interests in the Piceance Basin during 2014, no prior periods are presented.

	Year Ended December 31, 2014 (In thousands, except daily production)
Piceance Basin Production:	
Oil (MBbls)	23

Natural gas liquids (Mgal)	12,439
Natural gas (MMcf)	11,767
Total (Mboe)	2,280
Average daily production (Boe per day) (a)	10,806

(a) As the Piceance Basin assets were acquired in the WPX Acquisition, the production volumes and related average daily production is calculated from June 4, 2014, the date of closing, through December 31, 2014.

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Summary of Oil and Natural Gas Properties and Projects

Our most significant fields and regions are the Piceance Basin, Spraberry/War San, Texas Panhandle, East Binger, Jordan, Caprock, Lea, New Mexico Lower Abo, Deep Rock and Jalmat. As of December 31, 2014, these ten fields accounted for approximately 49% of our standardized measure and 60% of our total estimated proved reserves.

Piceance Basin. Legacy's wells in the Piceance Basin are located in Garfield County, Colorado in the Grand Valley, Parachute and Rulison fields. Most of the wells in these fields produce from the Williams Fork formation at depths of approximately 7,000 to 9,000 feet and some wells produce from the Wasatch formation at depths of 1,600 to 4,000 feet. Legacy's ownership in this basin is comprised of non-operated interests in 2,682 active wells acquired in the WPX Acquisition that escalate from an initial working interest of approximately 29% to approximately 37% on January 1, 2015 and 41% on January 1, 2016. As of December 31, 2014, our properties in the Piceance Basin contained 49.6 MMBoe (15% liquids) of net proved reserves with a standardized measure of $313.4 million. The average net daily production from this field was 11,085 Boe/d for the fourth quarter of 2014. The estimated reserve life (R/P) for this field is 12.2 years based on the annualized fourth quarter production rate.

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 259 active wells (252 producing, 7 injecting) in this field with working interests ranging from 12.9% to 100% and net revenue interests ranging from 9.6% to 90.8%. We also own another 177 non-operated wells (175 producing, 2 injecting). As of December 31, 2014, our properties in the Spraberry/War San field contained 10.6 MMBoe (67% liquids) of net proved reserves with a standardized measure of $184.5 million. The average net daily production from this field was 2,731 Boe/d for the fourth quarter of 2014. The estimated reserve life (R/P) for this field is 10.6 years based on the annualized fourth quarter production rate.

19 wells were drilled on our properties in the Spraberry/War San field in 2014. We have identified 52 more proved undeveloped projects, primarily 40-acre infill drilling locations, and eight 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 703 wells (660 producing, 43 injecting) in the Texas Panhandle fields with working interests ranging from 33.3% to 100% and net revenue interests ranging from 19.9% to 100%. We also own another 420 non-operated wells (411 producing, 9 injecting). As of December 31, 2014, our properties in the Texas Panhandle fields contained 4.8 MMBoe (72% liquids) of net proved reserves with a standardized measure of $69.1 million. The average net daily production from these fields was 1,079 Boe/d for the fourth quarter of 2014. The estimated reserve life (R/P) for these fields is 12.2 years based on the annualized fourth quarter production rate.

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 68 wells (47 producing, 21 injecting) in the East Binger field, and Legacy owns a working interest of 55.67% and net revenue interest of 46.2% in the East Binger Unit. As of December 31, 2014, our properties in the East Binger field contained 3.8 MMBoe (69% liquids) of net proved reserves with a standardized measure of $57.2 million. The average net daily production from this field was 704 Boe/d for the fourth quarter of

2014. The estimated reserve life (R/P) for the field is 14.9 years based on the annualized fourth quarter production rate. Our engineers have identified five proved undeveloped drilling locations in this 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 112 wells (79 producing, 33 injecting) in the field with working interests ranging from 53.1% to 95% and net revenue interests ranging from

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12.9% to 82.4%. We also own another 190 non-operated wells (143 producing, 47 injecting). As of December 31, 2014, our properties in the Jordan field contained 2.4 MMBoe (93% liquids) of net proved reserves with a standardized measure of $44.7 million. The average net daily production from the field was 487 Boe/d for the fourth quarter of 2014. The estimated reserve life (R/P) of the field is 13.4 years based on the annualized fourth quarter production rate. Our engineers have identified 21 proved undeveloped infill drilling projects, and 10 behind-pipe or proved developed non-producing projects and several unproved drilling locations in the field.

Caprock Field. The Caprock field is located in Chaves and Lea Counties, Texas. The field produces under CO2 flood from the Queen formation at depths of 2,700 to 3,100 feet. We operate 134 wells (58 producing, 76 injecting) in the field with working interests ranging from 78.4% to 100% and net revenue interests ranging from 52.0% to 87.5%. As of December 31, 2014, our properties in the Caprock field contained 4.6 MMBoe (100% liquids) of net proved reserves with a standardized measure of $41.6 million. The average net daily production from this field was 609 Boe/d for the fourth quarter of 2014. The estimated reserve life (R/P) for the field is 20.5 years based on the annualized production rate.

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 9,500 feet to 11,500 feet. These properties also produce from the Morrow, Devonian, Delaware and Pennsylvania formations at depths ranging from 6,500 feet to 14,500 feet. We operate 25 wells (23 producing, 2 injecting) in the Lea Field with working interests ranging from 12.5% to 100% and net revenue interests ranging from 4.1% to 81.3%. As of December 31, 2014, our properties in the Lea Field contained 1.9 MMBoe (73% liquids) of net proved reserves with a standardized measure of $41.2 million. The average net daily production from this field was 353 Boe/d for the fourth quarter of 2014. The estimated reserve life (R/P) of the field is 14.9 years based on the annualized fourth quarter production rate. Our engineers have identified four additional proved and several unproved undeveloped horizontal Bone Spring drilling locations in the field.

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. We operate 45 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 26 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 45 operated wells have come online since January 1, 2010, which is resulting in significant flush production from these wells. As of December 31, 2014, our properties in the Lower Abo play contained 1.7 MMBoe (57% liquids) of net proved reserves with a standardized measure of $38.9 million. The average net daily production from this field was 843 Boe/d for the fourth quarter of 2014. The estimated reserve life (R/P) for the field is 5.6 years based on the annualized fourth quarter production rate, which is materially impacted by the flush production from recent drilling activity by the prior operator described above. We expect this production rate to continue to drop materially in 2015. Our engineers have identified four proved undeveloped drilling projects as well as several unproved drilling projects in this area.

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 4,000 to 12,200 feet. We operate 31 wells (30 producing, 1 injecting) in the field with working interests ranging from 50% to 100% and net revenue interests ranging from 43.8% to 81.3%. We also own 21 non-operated wells (16 producing, 5 injecting). As of December 31, 2014, our properties in the Deep Rock field contained 1.7 MMBoe (97% liquids) of net proved reserves with a standardized measure of $38.0 million. The average net daily production from this field was 328 Boe/d for the fourth quarter of 2014. The estimated reserve life (R/P) for the field is 14.4 years based on the annualized production rate. Our engineers have identified three 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.

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

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3,800 feet. We operate 129 wells (82 producing, 47 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 15 non-operated wells in the field. As of December 31, 2014, our properties in the Jalmat field contained 2.0 MMBoe (93% liquids) of net proved reserves with a standardized measure of $34 million. The average net daily production from this field was 299 Boe/d for the fourth quarter of 2014. The estimated reserve life (R/P) for the field is 18.3 years based on the annualized fourth quarter production rate. Our engineers have identified seven proved undeveloped infill drilling projects in the field.

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.

The following information represents estimates of our proved reserves as of December 31, 2014, 2013 and 2012. 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, 2014, 2013 and 2012. As a result of this methodology, we used an average WTI posted price of $91.48 per Bbl for oil and an average Platts' Henry Hub natural gas price of $4.35 per MMBtu to calculate our estimate of proved reserves as of December 31, 2014. Please see the table below.

	As of December 31,		
	2014	2013	2012
Reserve Data:			
Estimated net proved reserves:			
Oil (MMBbls)	56.9	57.0	52.0
Natural Gas Liquids (MMBbls)	12.4	4.1	4.6
Natural Gas (Bcf)	418.0	159.0	159.3
Total (MMBoe)	139.0	87.6	83.2
Proved developed reserves (MMBoe)	126.4	75.9	75.0
Proved undeveloped reserves (MMBoe)	12.6	11.7	8.2
Proved developed reserves as a percentage of total proved reserves	91 %	87 %	90 %
Standardized measure (in millions)(a)	$1,754.6	$1,557.0	$1,425.9
Oil and Natural Gas Prices(b)			
Oil - WTI per Bbl	$91.48	$93.42	$91.17
Natural gas - Henry Hub per MMBtu	$4.35	$3.67	$2.76

(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.”

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(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 as posted by Plains Marketing L.P. and Platts Gas Daily for oil and natural gas, respectively, 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 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 FASB 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 2014, 2013 and 2012, we paid LaRoche approximately $472,994, $400,646 and $306,861, 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.

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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 37-year career with four publicly traded oil and natural gas producing companies, including Legacy. He has over 27 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.

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, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014(a)	2013	2012(b)
Production:			
Oil (MBbls)	4,784	4,475	3,337
Natural gas liquids (MGal)	30,861	13,272	14,607
Gas (MMcf)	25,936	14,328	10,417
Total (MBoe)	9,841	7,179	5,421
Average daily production (Boe per day)	26,962	19,668	14,811
Average sales price per unit (excluding commodity derivative cash settlements):			
Oil (per Bbl)	$82.94	$90.62	$85.78
NGL (per Gal)	$0.89	$1.06	$1.00
Gas (per Mcf)	$4.17	$4.60	$4.38
Combined (per Boe)	$54.09	$67.63	$63.91
Average sales price per unit (including commodity derivative cash settlements):			
Oil (per Bbl)	$81.80	$87.46	$82.72
NGL (per Gal)	$0.89	$1.06	$1.00
Gas (per Mcf)	$4.48	$5.09	$5.93
Combined (per Boe)	$54.36	$66.64	$65.00
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$18.98	$19.89	$19.08
Ad valorem taxes	$1.22	$1.65	$1.76
Production and other taxes	$3.20	$4.11	$3.83
General and administrative	$3.96	$4.03	$4.52
Depletion, depreciation and amortization	$17.65	$22.07	$18.84

(a) Reflects the production and operating results of the WPX Acquisition properties from the closing date on June 4, 2014 through December 31, 2014.

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

Productive Wells

The following table sets forth information at December 31, 2014 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the product of our fractional working interests owned in gross wells.

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	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated	3,334	2,611	585	465	3,919	3,076
Non-operated	3,273	304	3,929	927	7,202	1,231
Total	6,607	2,915	4,514	1,392	11,121	4,307

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2014 relating to our leasehold acreage.

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross(c)	Net(d)	Gross(c)	Net(d)
Total	956,198	406,232	179,988	51,958

(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, 2014, 2013 and 2012. 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,		
	2014	2013	2012
Gross:			
Development			
Productive	122	104	57
Dry	—	—	—
Total	122	104	57
Exploratory			
Productive	—	2	3
Dry	—	—	—
Total	—	2	3
Net:			
Development			
Productive	41.1	28.3	21.4

Dry	—	—	—
Total	41.1	28.3	21.4
Exploratory			
Productive	—	0.1	0.15
Dry	—	—	—
Total	—	0.1	0.15

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Summary of Development Projects

For the year ended December 31, 2014, we invested approximately $133.4 million in implementing our development strategy, including $78.6 million related to the development of proved undeveloped reserves. We estimate that our capital expenditures for the year ending December 31, 2015 will be approximately $30 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.

Present Activities

As of December 31, 2014, we were in the process of drilling 4 gross (1.8 net) wells, all of which were development wells.

Operations

General

We operate approximately 50% 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 the working interest owners, including 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, Northwest Pipeline natural gas, NGPL Midcon natural gas, California SoCal natural gas, San Juan Basin 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, none of our current derivative counterparties require us to post

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collateral. 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."

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.

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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 23, 2015, there were 69,208,533 units outstanding, held by approximately 122 holders of record, including units held by our Founding Investors. This number reflects only the holders of record, and does not reflect all beneficial owners of units, such as those who hold their units through a broker.

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	Cash Distribution
2014	High	Low	per Unit	to General Partner
First Quarter	$28.50	$24.75	$0.595	$10,895
Second Quarter	$31.84	$25.10	$0.610	$11,170
Third Quarter	$32.61	$26.60	$0.610	$11,170
Fourth Quarter	$29.71	$10.05	$0.610	$11,170 (a)

	Price Ranges		Cash Distribution	Cash Distribution
2013	High	Low	per Unit	to General Partner
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) This distribution was paid to our general partner concurrent with our distribution to unitholders on February 13, 2015.

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;
- distributions to holders of the Preferred Units; and

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

We last paid a quarterly cash distribution of $0.61 per unit.

Distributions on the Preferred Units are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of the Partnership's general partner. Distributions on the Series A Preferred Units will be payable from, and including, the date of the original issuance to, but not including April 15, 2024 at an initial rate of 8.00% per annum of the stated liquidation preference. Distributions on the Series B Preferred Units will be payable from, and including, the date of the original issuance to, but not including June 15, 2024 at an initial rate of 8.00% per annum of the

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stated liquidation preference. Distributions accruing on and after April 15, 2024 for the Series A Preferred Units and June 15, 2024 for the Series B Preferred Units will accrue at an annual rate equal to the sum of (a) three-month LIBOR as calculated on each applicable date of determination and (b) 5.24% for Series A and 5.26% for Series B, based on the $25.00 liquidation preference per Preferred Unit.

At any time on or after April 15, 2019 or June 15, 2019, Legacy may redeem the Series A Preferred Units or Series B Preferred Units, respectively, in whole or in part at a redemption price of $25.00 per Preferred Unit plus an amount equal to all accumulated and unpaid distributions thereon through and including the date of redemption, whether or not declared. Legacy may also redeem the Preferred Units in the event of a change of control.

Recent Sales of Unregistered Securities

None.

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,				
	2014(a)	2013	2012(b)	2011	2010(c)
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Oil sales	$396,774	$405,536	$286,254	$264,473	$172,754
Natural gas liquids sales	27,483	14,095	14,592	18,888	13,670
Natural gas sales	108,042	65,858	45,614	53,524	29,965
Total revenues	532,299	485,489	346,460	336,885	216,389
Expenses:					
Oil and natural gas production	198,801	154,679	112,951	96,914	69,228
Production and other taxes	31,534	29,508	20,778	20,329	12,683
General and administrative	38,980	28,907	24,526	23,084	19,265
Depletion, depreciation, amortization and accretion	173,686	158,415	102,144	88,178	62,894
Impairment of long-lived assets	448,714	85,757	37,066	24,510	13,412
(Gain) loss on disposal of assets	(2,479)	579	(2,496)	(625)	592
Total expenses	889,236	457,845	294,969	252,390	178,074
Operating income (loss)	(356,937)	27,644	51,491	84,495	38,315
Other income (expense):					
Interest income	873	776	16	15	10
Interest expense	(67,218)	(50,089)	(20,260)	(18,566)	(25,766)
Equity in income of partnerships	428	559	111	138	97
Net gains (losses) on commodity derivatives	138,092	(13,531)	38,493	6,857	(1,400)
Other	258	18	(118)	152	90
Income (loss) before income taxes	(284,504)	(34,623)	69,733	73,091	11,346
Income taxes	859	(649)	(1,096)	(1,030)	(537)
Net income (loss)	(283,645)	(35,272)	68,637	72,061	10,809
Distributions to preferred unitholders	(11,694)	—	—	—	—
Net income (loss) attributable to unitholders	$(295,339)	$(35,272)	$68,637	$72,061	$10,809

Income (loss) per unit					
Basic and diluted	$(4.92)	$(0.62)	$1.40	$1.63	$0.27
Distributions paid per unit	$2.405	$2.31	$2.23	$2.14	$2.08

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Cash Flow Data:					
Net cash provided by operating activities	$207,216	$241,134	$149,641	$184,237	$101,371
Net cash used in investing activities	$(632,414)	$(209,401)	$(696,279)	$(206,816)	$(285,246)
Net cash provided by (used in) financing activities	$423,339	$(32,658)	$546,996	$22,252	$183,136
Capital expenditures	$640,414	$204,911	$704,191	$207,565	$311,277

	Historical As of December 31,				
	2014(a)	2013	2012(b)	2011	2010(c)
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$725	$2,584	$3,509	$3,151	$3,478
Other current assets	191,529	72,115	84,401	56,634	47,120
Oil and natural gas properties, net of accumulated depletion, depreciation and amortization	1,639,974	1,535,429	1,571,926	959,329	843,836
Other assets	66,378	49,705	30,163	24,374	14,992
Total assets	$1,898,606	$1,659,833	$1,689,999	$1,043,488	$909,426
Current liabilities	$97,576	$93,890	$103,723	$97,450	$72,955
Long term debt	938,876	878,693	775,838	337,000	325,000
Other long-term liabilities	224,949	176,854	140,158	120,703	119,732
Partners' equity	637,205	510,396	670,280	488,335	391,739
Total liabilities and partners' equity	$1,898,606	$1,659,833	$1,689,999	$1,043,488	$909,426

(a) Reflects Legacy's purchase of the oil and natural gas properties acquired in the WPX Acquisition as of the closing date of the acquisition on June 4, 2014. Consequently, the operations of these acquired properties are only included for the period from the closing date of the acquisition through December 31, 2014.

(b) 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 on December 20, 2012 through December 31, 2012 and thereafter.

(c) Reflects Legacy's purchase of the oil and natural gas properties acquired in Wyoming and in the acquisition of certain oil and natural gas properties located primarily in the Permian Basin from a subsidiary of Concho Resources, Inc. 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.

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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. During 2014, we consummated $536.3 million of acquisitions, excluding $50.5 million of non-cash asset retirement obligations, consisting of 6 individually immaterial transactions and the acquisition of certain oil and natural gas properties located in the Piceance Basin of Colorado from a subsidiary of WPX Energy, Inc. (the "WPX Acquisition"). The operating results of these acquisitions have been included from their respective acquisition dates.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.

Trends Affecting Our Business and Operations

Acquisitions have been financed with a combination of proceeds from bank borrowings, issuance of notes, issuance of additional units, issuance of preferred units, issuance of incentive distribution 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 the current 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.

Outlook. The current supply and demand environment for crude oil and natural gas has resulted in a significant decrease of commodity prices. Based on the drastic decrease in commodity prices in the fourth quarter of 2014, we expect a challenging 2015. Crude oil prices declined from a high of $107.95 per Bbl in June 2014 to $53.45 per Bbl at December 31, 2014. Primarily as a result of the drastic decline in commodity prices, in 2014, we had to recognize an impairment expense of $448.2 million in the value of our oil and natural gas properties. The drastic decline in commodity prices is also primarily responsible for a decrease in operating income from $27.0 million in the third quarter of 2014 to an operating loss of $445.1 million, including impairment of $440.1 million, in the fourth quarter of 2014. A sustained period of reduced commodity prices will have an adverse effect on our operating income in future periods resulting from decreased revenues and higher depletion rates and a significant portion of our development

projects may become uneconomic and cause write downs of the value of our oil and natural gas properties. However, we do not anticipate future operating losses, if any, to be at the level recorded in the fourth quarter of 2014 as we have significantly impaired substantially all of our properties that are

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at risk under the current price environment. Finally, due to the decrease in commodity prices and the resulting decreased value of our oil and natural gas properties, the borrowing base of our revolving credit facility was reduced to $700 million on February 23, 2015 pursuant to the Fourth Amendment to our revolving credit facility. As a result, we reduced our 2015 capital expenditure budget to approximately $30.0 million from $133.4 million in 2014. In addition, under the current market prices for oil and natural gas we may also not be able to sustain our current distribution levels to our unitholders.

Oil prices have declined significantly since November 2014. This has reduced, and will continue to reduce, our revenues and cash flows from operations. In order to mitigate the impact of lower oil and natural gas prices on our cash flows, we are a party to derivative agreements, and we intend to enter into derivative agreements in the future to reduce the impact of oil and natural gas price volatility on our cash flows. By removing a portion of our price volatility on our future oil and natural gas production through 2018, we have mitigated, but not eliminated, the potential effects of changing oil and natural gas prices on our cash flows from operations for those periods. Commodity prices may be depressed for an extended period of time, which could alter our acquisition and exploration plans, and adversely affect our growth strategy and ability to access additional capital in the capital markets and through our revolving credit facility.

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.

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Operating Data

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

	Year Ended December 31,		
	2014(b)	2013	2012(c)
	(In thousands, except per unit data and production)		
Revenues			
Oil sales	$396,774	$405,536	$286,254
Natural gas liquids sales	27,483	14,095	14,592
Natural gas sales	108,042	65,858	45,614
Total revenues	$532,299	$485,489	$346,460
Expenses:			
Oil and natural gas production	$186,750	$142,798	$103,409
Ad valorem taxes	12,051	11,881	9,542
Total	$198,801	$154,679	$112,951
Production and other taxes	$31,534	$29,508	$20,778
General and administrative excluding LTIP	$35,185	$24,093	$20,980
LTIP expense	3,795	4,814	3,546
Total general and administrative	$38,980	$28,907	$24,526
Depletion, depreciation, amortization and accretion	$173,686	$158,415	$102,144
Commodity derivative cash settlements:			
Oil derivative cash settlements paid	(5,431)	(14,160)	(10,211)
Natural gas derivative cash settlements received	8,097	7,104	16,113
Total commodity derivative cash settlements	2,666	(7,056)	5,902
Production:			
Oil (MBbls)	4,784	4,475	3,337
Natural gas liquids (MGal)	30,861	13,272	14,607
Natural gas (MMcf)	25,936	14,328	10,417
Total (MBoe)	9,841	7,179	5,421
Average daily production (Boe/d)	26,962	19,668	14,811
Average sales price per unit (excluding commodity derivative cash settlements):			
Oil price (per Bbl)	$82.94	$90.62	$85.78
Natural gas liquids price (per Gal)	$0.89	$1.06	$1.00
Natural gas price (per Mcf)(a)	$4.17	$4.60	$4.38
Combined (per Boe)	$54.09	$67.63	$63.91
Average sales price per unit (including commodity derivative cash settlements):			
Oil price (per Bbl)	$81.80	$87.46	$82.72
Natural gas liquids price (per Gal)	$0.89	$1.06	$1.00
Natural gas price (per Mcf)(a)	$4.48	$5.09	$5.93
Combined (per Boe)	$54.36	$66.64	$65.00
Average WTI oil spot price (per Bbl)	$92.91	$97.98	$94.05
Average Henry Hub natural gas index price (per Mcf)	$4.26	$3.66	$2.79
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$18.98	$19.89	$19.08
Ad valorem taxes	$1.22	$1.65	$1.76
Production and other taxes	$3.20	$4.11	$3.83
General and administrative excluding LTIP	$3.58	$3.36	$3.87
Total general and administrative	$3.96	$4.03	$4.52

Depletion, depreciation, amortization and accretion	$17.65	$22.07	$18.84

(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 WPX Acquisition from the closing date of the acquisition on June 4, 2014 through December 31, 2014.

(c) 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.

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Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Legacy's revenues from the sale of oil were $396.8 million and $405.5 million for the years ended December 31, 2014 and 2013, respectively. Legacy's revenues from the sale of NGLs were $27.5 million and $14.1 million for the years ended December 31, 2014 and 2013, respectively. Legacy's revenues from the sale of natural gas were $108.0 million and $65.9 million for the years ended December 31, 2014 and 2013, respectively. The $8.8 million decrease in oil revenue reflects a decrease in average realized price of $7.68 per Bbl (8%) to $82.94 for the year ended December 31, 2014 from $90.62 for the year ended December 31, 2013, partially offset by an increase in oil production of 309 MBbls (7%). The decrease in realized oil price was primarily caused by a decrease in the average WTI crude oil price of $5.07, and to a lesser extent, a worsening of our crude oil differentials in the Rocky Mountain and Permian Basin regions during the year ended December 31, 2014 compared to the same period in 2013. The increase in production is due primarily to acquisitions of oil and natural gas properties and development activities that were primarily focused on oil-weighted projects in the Permian Basin. The $13.4 million increase in NGL revenues reflects an increase in NGL production of 17,589 MGals (133%) during 2014, partially offset by a decrease in realized NGL price of $0.17 per Gal (16%) to $0.89 per Gal for the year ended December 31, 2014 from $1.06 per Gal for the year ended December 31, 2013. The increase in NGL production is due primarily to 12,439 MGals of NGL production related to Legacy's purchase of oil and natural gas properties in the WPX Acquisition as well as other recent acquisitions. The $42.2 million increase in natural gas revenues reflects an increase in our natural gas production volumes partially offset by a decrease in our realized natural gas prices. Our natural gas production increased by approximately 11,608 MMcf (81%), primarily due to our acquisitions, most notably the WPX Acquisition (11,767 MMcf), as well as our development activities. These increases were partially offset by natural declines in our existing assets, most notably our Lower Abo assets, as well as third party infrastructure issues and plant and gathering downtime related to inclement weather that adversely impacted our natural gas production mostly in the Permian Basin. Average realized gas prices decreased by $0.43 per Mcf (9%) to $4.17 per Mcf for the year ended December 31, 2014 from $4.60 per Mcf for the year ended December 31, 2013 while the average NYMEX Henry Hub natural gas price increased by $0.60 per Mcf over the same time period. This decrease in realized prices relative to the increase in index prices is due to the inclusion of the significant natural gas volumes from the WPX Acquisition. As our historical natural gas volumes, particularly those produced from assets in the Permian Basin, were primarily accounted for inclusive of the NGL content contained within the natural gas volumes, we historically received a price greater than the NYMEX Henry Hub index price. However, the natural gas volumes from the WPX Acquisition are accounted for after the separation of the NGL content and receive a price less than the NYMEX Henry Hub index price due to regional price differentials. As these volumes account for approximately 45% of all of our reported natural gas volumes, their inclusion dramatically reduced our realized price per Mcf, on a relative basis.

For the year ended December 31, 2014, Legacy recorded $138.1 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. The net gain recognized during 2014 was primarily due to the significant decrease in oil futures prices during 2014. For the year ended December 31, 2013, Legacy recorded $13.5 million of net losses on oil and natural gas derivatives. Settlements of such contracts resulted in cash receipts of $2.7 million and cash payments of $7.1 million during 2014 and 2013, respectively.

Legacy's oil and natural gas production expenses, excluding ad valorem taxes, increased to $186.8 million ($18.98 per Boe) for the year ended December 31, 2014 from $142.8 million ($19.89 per Boe) for the year ended December 31, 2013. Production expenses increased primarily due to $26.1 million of expenses related to properties acquired in the WPX 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 decreased in 2014 compared to 2013 due to the inclusion of lower cost production from the WPX Acquisition. Legacy’s ad valorem tax expense increased to $12.1 million ($1.22 per Boe) for the year ended December 31, 2014 from $11.9 million ($1.65 per Boe) for the year ended December 31, 2013 due to increased well counts from our acquisition of oil and natural gas properties.

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Legacy's production and other taxes were $31.5 million and $29.5 million for the years ended December 31, 2014 and 2013, respectively. Production and other taxes increased because of higher total revenues in 2014, as production and other taxes are assessed as a percentage of revenue and that percentage remained relatively unchanged between 2014 and 2013.

Legacy's general and administrative expenses were $39.0 million and $28.9 million for the years ended December 31, 2014 and 2013, respectively. General and administrative expenses increased approximately $10.1 million between periods primarily due to $4.5 million of increased acquisition-related expenses and a $3.4 million increase in salary and benefit expenses, net of overhead recovery, due to the hiring of additional personnel commensurate with the growth of our asset base. These increases were partially offset by a $1.0 million decrease in unit-based compensation due to a decrease in our unit price between December 31, 2014 and December 31, 2013.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $173.7 million and $158.4 million for the years ended December 31, 2014 and 2013, respectively. DD&A increased primarily due to approximately $20.2 million of depletion expense related to the properties acquired in the WPX Acquisition. Our depletion rate per Boe for the year ended December 31, 2014 was $17.65 compared to $22.07 for the year ended December 31, 2013. This decrease is primarily driven by a lower net cost basis on our historical assets due to previously recognized depletion and impairment.

Impairment expense was $448.7 million and $85.8 million for the years ended December 31, 2014 and 2013, respectively. In 2014, Legacy recognized $413.3 million of impairment expense in 250 separate producing fields, due to the significant decrease in commodity prices during the year ended December 31, 2014 which decreased the expected future cash flows below the carrying value of the assets. As we have historically grown through the acquisition of oil and natural gas properties, most of which were purchased during higher commodity price environments, the sharp decline in oil and natural gas prices during the latter portion of 2014 resulted in a corresponding decrease in the expected future cash flows of such assets from the date of their acquisition as compared to December 31, 2014. As evidenced above, this decrease was not limited to any one field or area of operation, as it impacted the value of oil and natural gas assets across our portfolio. Additionally, we recorded impairment of $35.0 million related to unproved properties acquired since 2010 that, in the current and expected future commodity price environment, are no longer economically viable. The remaining $0.5 million of impairment was related to the impairment of goodwill recognized on the acquisition of a company in 2010. At the time of acquisition, the company was performing accounting and engineering consulting for certain third-parties. As the company is no longer performing such services, we impaired the remaining goodwill. In 2013, Legacy recognized impairment expense of $78.0 million 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.

Interest expense was $67.2 million and $50.1 million for the years ended December 31, 2014 and 2013, respectively. The increase in interest expense is primarily due to an increase of $20.1 million of interest expense related to a full year of interest on the issuance of the Senior Notes in December 2012 and May 2013 as well as the interest related to our Senior Notes issued in May 2014. This increase was partially offset by a reduction of $2.7 million of interest expense related to our revolving credit agreement due to a reduction in average balance outstanding as well as reduced interest rate expenses related to our interest rate swaps, which decreased by $0.6 million to $0.6 million in 2014 from $1.2 million in 2013. Cash payments on our interest rate swaps were $3.2 million and $6.0 million in 2014 and 2013, respectively.

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

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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. Accordingly, the net loss recognized during the year ended December 31, 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)/receipts of $(7.1) million and $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 expense 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.

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 increases 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

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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 cost 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.

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;

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- Minimum payments received in excess of overriding royalty interest earned;
- Equity in EBITDA of equity method investee;
- Net (gains) losses on commodity derivatives;
- Net cash settlements received (paid) on commodity derivatives; and
- Transaction expenses related to acquisitions.

The following table presents a reconciliation of Legacy's consolidated net income (loss) to Adjusted EBITDA for the years ended December 31, 2014, 2013 and 2012, respectively.

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Net income (loss)	$(283,645)	$(35,272)	$68,637
Plus:			
Interest expense	67,218	50,089	20,260
Income tax expense	(859)	649	1,096
Depletion, depreciation, amortization and accretion	173,686	158,415	102,144
Impairment of long-lived assets	448,714	85,757	37,066
(Gain) loss on disposal of assets	(2,479)	579	(2,496)
Equity in income of equity method investees	(428)	(559)	(111)
Unit-based compensation expense	3,795	4,814	3,546
Minimum payments received in excess of overriding royalty interest earned(a)	1,381	1,051	—
Equity in EBITDA of equity method investee(b)	805	727	—
Net (gains) losses on commodity derivatives	(138,092)	13,531	(38,493)
Net cash settlements received (paid) on commodity derivatives	2,666	(7,056)	5,902
Transaction expenses related to acquisitions	5,425	722	1,092
Adjusted EBITDA	$278,187	$273,447	$198,643

(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, 2014, Adjusted EBITDA increased 2% to $278.2 million from $273.4 million for the year ended December 31, 2013. This increase is due primarily to increased production from the WPX Acquisition and other recent acquisitions as well as cash receipts of $2.7 million on our commodity derivatives during 2014 compared to cash payments of $7.1 million during 2013. This increase was partially offset by higher production expenses and lower realized commodity prices. For the year ended December 31, 2013, Adjusted EBITDA increased 38% to $273.4 million from $198.6 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 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.

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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 and preferred 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 April 1, 2019.

Our commodity derivatives position, which we use to mitigate commodity price volatility and support our borrowing capacity, resulted in $2.7 million of cash receipts in the year ended December 31, 2014. 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 $840.9 million was available for borrowings as of December 31, 2014 and $569.9 million was available as of February 23, 2015 after the borrowing base was redetermined in connection with our entering into the Fourth Amendment to our revolving credit facility, will provide us sufficient working capital in 2015 to meet our planned capital expenditures of $30 million, cash distributions of $19.0 million on our Preferred Units and up to $168.9 million of annualized cash distributions on our units, which includes the $42.2 million of distributions on our units attributable to the fourth quarter of 2014 that were paid in the first quarter of 2015. 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, given the current commodity price environment, there is no guarantee that the board will maintain our most recent quarterly distribution rate of $0.61 per unit, and may decrease such rate. Please read "— Financing Activities — Our Revolving Credit Facility."

Cash Flow from Operations

Legacy's net cash provided by operating activities was $207.2 million and $241.1 million for the years ended December 31, 2014 and 2013, respectively, with the 2014 period being unfavorably impacted by higher production expenses and lower realized commodity prices, partially offset by higher production volumes primarily related to acquisitions, most notably the WPX Acquisition.

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 Acquisition, and higher realized commodity prices, partially offset by higher expenses.

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 $638.9 million for the year ended December 31, 2014. The total includes $505.5 million related to the WPX Acquisition and 6 individually immaterial acquisitions and $133.4 million of development projects.

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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.

We currently anticipate that our development capital budget, which predominantly consists of drilling, CO2 injection, recompletion and well stimulation projects, will be $30 million for the year ending December 31, 2015. Our borrowing capacity under our revolving credit facility is $569.9 million as of February 23, 2015. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of a CO2 purchase commitment and certain projects managed by other operators. 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.

We enter into oil and natural gas derivatives to reduce the impact of oil and natural gas price volatility on our operations. At February 23, 2015, we had in place oil, natural gas and price differential derivatives covering significant portions of our estimated 2015 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, none of our current counterparties require us to post margin. 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 23, 2015 covering the period from January 1, 2015 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, Rocky Mountain CIG, Northwest Pipeline, NGPL Midcon, California SoCal NGI and San Juan Basin prices of natural gas.

Oil Swaps:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2015	1,056,301	$93.93	$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	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2015	18,619,300	$4.39	$3.98 - $5.82
2016	1,419,200	$4.30	$4.12 - $5.30

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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 and again in late 2014. 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 23, 2015:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2015	1,997,000	$(2.02)	$(1.65) - $(2.55)

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 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. For example, at an annual average WTI market price of $50.00 the summary positions below would result in a net price of $74.61, $75.00 and $75.00, for 2015, 2016 and 2017, respectively. The following table summarizes the three-way oil collar contracts currently in place as of February 23, 2015:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2015	1,362,800	$65.08	$89.69	$111.84
2016	621,300	$63.37	$88.37	$106.40
2017	72,400	$60.00	$85.00	$104.20

We have also entered into multiple NYMEX WTI crude oil derivative enhanced swap contracts. The first type of enhanced swap contract combines buying a lower-priced put, selling a higher-priced put, and using the net proceeds from these positions to simultaneously obtain a swap at above market prices (“enhanced swap price”). If the market price is at or above the higher-priced short put, this contract allows us to settle at the enhanced swap price. If the market price is below the higher-priced short put but above the lower-priced long put, this contract allows us to settle for the market price plus the spread between the enhanced swap price and the higher-priced short put. If the market price is at or below the lower-priced long put, this contract allows us to settle for the lower-priced long put plus the spread between the enhanced swap price and the higher-priced short put. For example, at an annual average WTI market price of $50.00 the summary positions below would result in a net price of $66.70, $65.85 and $65.50, for 2016, 2017 and 2018, respectively. The following table summarizes these type of enhanced swap contracts currently in place as of February 23, 2015:

Calendar Year	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
2016	183,000	$57.00	$82.00	$91.70
2017	182,500	$57.00	$82.00	$90.85
2018	127,750	$57.00	$82.00	$90.50

We have also entered into other multiple NYMEX WTI crude oil derivative enhanced swap contracts. This second type of enhanced swap contract combines selling a put and using the net proceeds to simultaneously obtain a swap at above market prices, i.e. the enhanced swap price. If the market price is at or above the put, this contract allows us to settle at the enhanced swap price. If the market price is below the put, this contract allows us

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to settle for the market price plus the spread between the enhanced swap price and the put price. For example, at an annual average WTI market price of $50.00 the summary position below would result in a net price of $67.09. The following table summarizes these type of enhanced swap contracts currently in place as of February 23, 2015:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Swap Price per Bbl
2015	868,000	$76.59	$93.68

We have also entered into multiple NYMEX Henry Hub natural gas 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 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 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. For example, at an annual average Henry Hub market price of $3.00 the summary positions below would result in a net price of $3.55, $3.50 and $3.50, for 2015, 2016 and 2017, respectively. The following table summarizes the three-way natural gas collar contracts currently in place as of February 23, 2015:

Calendar Year	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
2015	8,040,000	$3.66	$4.21	$5.01
2016	5,580,000	$3.75	$4.25	$5.08
2017	5,040,000	$3.75	$4.25	$5.53

We have also entered into multiple Henry Hub NYMEX to Northwest Pipeline, NGPL Midcon, California SoCal NGI, San Juan Basin and West Texas Waha natural gas differential swaps paying a floating differential and receiving a fixed differential for a portion of its future natural gas production as indicated below:

	2015	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	12,000,000	$(0.13)
NGPL	480,000	$(0.15)
SoCal	240,000	$0.19
San Juan	480,000	$(0.12)
Waha	6,000,000	$(0.10)

Financing Activities

Legacy’s net cash provided by financing activities was $423.3 million for the year ended December 31, 2014, compared to net cash used of $32.7 million for the year ended December 31, 2013. During the year ended December 31, 2014, total net repayments under our revolving credit facility were $239.0 million while we raised $297.0 million in proceeds, net of original issue discount, but excluding other offering expenses paid by Legacy, in our private offering of 6.625% senior notes due 2021, resulting in total net borrowings of $58.0 million. Additionally we received net proceeds from the issuance of our 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") and 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units") in the amount of $229.5 million as well as $303.5 million of proceeds from our October public offering of units. Finally, Legacy had cash outflow during the

year ended December 31, 2014 in the amount of $157.6 million for distributions to unitholders and our Series A and Series B Preferred unitholders, which was funded from cash flow from operations. Cash used in financing activities during the year ended December 31, 2013, included $140.0 million in net repayments under our revolving credit facility while we raised $241.3 million in proceeds, net of original issue discount and fees paid to initial

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purchasers, but excluding other offering expenses paid by Legacy, in our private offering of 6.625% senior notes due 2021, resulting in total net borrowings of $101.3 million. Additionally, Legacy had cash outflow during the year ended December 31, 2013 in the amount of $132.7 million for distributions to unitholders which was funded from cash flow from operations.

On April 17, 2014, Legacy issued 2,000,000 of its Series A Preferred Units in a public offering at a price of $25.00 per unit. On May 12, 2014 Legacy issued an additional 300,000 Series A Preferred Units pursuant to the underwriters' option to purchase additional Series A Preferred Units. Legacy received aggregate net proceeds of approximately $55.2 million, after deducting underwriting discounts and offering expenses, from the offering of Series A Preferred Units during the year ended December 31, 2014.

On June 17, 2014, Legacy issued 7,000,000 of its Series B Preferred Units in a public offering at a price of $25.00 per unit. On July 1, 2014 Legacy issued an additional 200,000 Series B Preferred Units pursuant to the underwriters' option to purchase additional Series B Preferred Units. Legacy received aggregate net proceeds of approximately $174.3 million, after deducting underwriting discounts and offering expenses, from the offering of Series B Preferred Units during the year ended December 31, 2014.

The Series A Preferred Units and the Series B Preferred Units trade on the NASDAQ Global Select Market under the symbols "LGCYP" and "LGCYO," respectively.

On June 4, 2014, Legacy issued 300,000 incentive distribution units representing limited partner interests in Legacy (the "Incentive Distribution Units") to WPX Energy Rocky Mountain, LLC ("WPX") as part of the WPX Acquisition. The Incentive Distribution Units issued to WPX include 100,000 Incentive Distribution Units that immediately vested along with the ability to vest in up to an additional 200,000 Incentive Distribution Units (the "Unvested IDUs") in connection with any future asset sales or transactions completed with us pursuant to the terms of the IDR Holders Agreement. Incentive Distribution Units that are not issued to WPX or other parties will remain in Legacy's treasury for the benefit of all limited partners until such time as Legacy may make future issuances of Incentive Distribution Units.

8% Senior Notes Due 2020

On December 4, 2012, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $300 million of our 8% senior notes due 2020 (the "2020 Senior Notes"), which were subsequently registered through a public exchange offer that closed on January 8, 2014. The 2020 Senior Notes were issued at 97.848% of par. We received net proceeds of approximately $286.7 million, after deducting the discount to initial purchasers and offering expense paid by Legacy, and used the net proceeds from this offering to fund a portion of the consideration paid for the COG 2012 Acquisition.

We will have the option to redeem the 2020 Senior Notes, in whole or in part, at any time on or after December 1, 2016, at the specified redemption prices set forth below together with any accrued and unpaid interest to the date of redemption, if redeemed during the twelve-month period beginning on December 1 of the years indicated below.

Year	Percentage
2016	104.000 %
2017	102.000 %
2018	100.000 %

Prior to December 1, 2016, we may redeem all or any part of the 2020 Senior Notes at the "make-whole" redemption price. In addition, prior to December 1, 2015, we may at our option, redeem up to 35% of the aggregate principal amount of the 2020 Senior Notes at the redemption price of 108% with the net proceeds of a public or private equity offering. We may be required to offer to repurchase the 2020 Senior Notes at a purchase price of 101% of the

principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. Our and Legacy Reserves Finance Corporation's obligations under

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the 2020 Senior Notes are guaranteed by our 100% owned subsidiaries Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc. In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the properties of the guarantor; (ii) in connection with any sale or other disposition of sufficient capital stock of the guarantor so that it no longer qualifies as our Restricted Subsidiary (as defined in the indenture); (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance, covenant defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of the guarantor provided no default or event of default has occurred or is occurring; (vi) at such time the guarantor does not have outstanding guarantees of our, or any other guarantor's, other debt; or (vii) upon merging into, or transferring all of its properties to us or another guarantor and ceasing to exist. Refer to Note 14 - Subsidiary Guarantors in the Notes to the Consolidated Financial Statements for further details on our guarantors.

The indenture governing the 2020 Senior Notes limits our ability and the ability of certain of our subsidiaries to (i) sell assets; (ii) pay distributions on, repurchase or redeem equity interests or purchase or redeem our subordinated debt, provided that such subsidiaries may pay dividends to the holders of their equity interests (including Legacy) and we may pay distributions to the holders of our equity interests subject to the absence of certain defaults, the satisfaction of a fixed charge coverage ratio test and so long as the amount of such distributions does not exceed the sum of available cash (as defined in Legacy's partnership agreement) at Legacy, net proceeds from the sales of certain securities and return of or reductions to capital from restricted investments; (iii) make certain investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from certain of our subsidiaries to Legacy; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in certain transactions with affiliates; (ix) create unrestricted subsidiaries; and (x) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 2020 Senior Notes are rated investment grade by each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indenture) has occurred and is continuing, many of such covenants will terminate and Legacy and our subsidiaries will cease to be subject to such covenants. The indenture also includes customary events of default. Legacy is in compliance with all financial and other covenants of the 2020 Senior Notes.

6.625% Senior Notes Due 2021

On May 28, 2013, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $250 million of our 6.625% Senior Notes due 2021 (the "2021 Senior Notes"). The 2021 Senior Notes were issued at 98.405% of par. Legacy received approximately $240.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses paid by Legacy.

On May 13, 2014, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of an additional $300 million of our 6.625% 2021 Senior Notes. This issuance of our 2021 Senior Notes was at 99.0% of par. Legacy received approximately $291.8 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by Legacy.

The terms of the 2021 Senior Notes, including details related to our guarantors, are substantially identical to the terms of the 2020 Senior Notes with the exception of the interest rate and redemption provisions noted below. Legacy will have the option to redeem the 2021 Senior Notes, in whole or in part, at any time on or after June 1, 2017, at the specified redemption prices set forth below together with any accrued and unpaid interest, if any, to the date of redemption if redeemed during the twelve-month period beginning on June 1 of the years indicated below.

Year	Percentage	
2017	103.313	%
2018	101.656	%

2019 and thereafter	100.000	%

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Prior to June 1, 2017, Legacy may redeem all or any part of the 2021 Senior Notes at the “make-whole” redemption price as defined in the indenture. In addition, prior to June 1, 2016, Legacy may at its option, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes at the redemption price of 106.625% with the net proceeds of a public or private equity offering. Legacy may be required to offer to repurchase the 2021 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. The Partnership is in compliance with all financial and other covenants of the 2021 Senior Notes.

Our Revolving Credit Facility

Previous Credit Agreement

On March 10, 2011, Legacy entered into a five-year $1 billion secured revolving credit facility (as amended, the "Previous Credit Agreement"). Borrowings under the Previous Credit Agreement were set to mature on March 10, 2016.

Current Credit Agreement

On April 1, 2014, Legacy entered into a five-year $1.5 billion secured revolving credit facility with Wells Fargo Bank, National Association, as administrative agent, Compass Bank, as syndication agent, UBS Securities LLC and U.S. Bank National Association, as co-documentation agents and the lenders party thereto as amended by the Fourth Amendment to the credit facility on February 23, 2015 (the “Current Credit Agreement”). Borrowings under the Current Credit Agreement mature on April 1, 2019. Legacy's obligations under the Current Credit Agreement are secured by mortgages on over 80% of the total value of its oil and natural gas properties as well as a pledge of all of its ownership interests in our operating subsidiaries. The amount available for borrowing at any one time is limited to the borrowing base and contains a $2 million sub-limit for letters of credit. The borrowing base is currently set at $700 million. As of February 23, 2015, we have approximately $130 million drawn under the Current Credit Agreement leaving approximately $569.9 million of current availability. The borrowing base is subject to semi-annual redeterminations on or about April 1 and October 1 of each year. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. We also have the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of certain oil and natural gas properties where the purchase price is greater than 10% of the borrowing base. Any increase in the borrowing base requires the consent of all the lenders, and any decrease in or maintenance of the borrowing base must be approved by the lenders holding at least 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Current Credit Agreement. If the required lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Current Credit Agreement so long as it does not increase the borrowing base then in effect.

Legacy may at any time issue additional senior notes, whose proceeds are used to refinance such senior notes as well as an additional $300 million in aggregate principal amount of new senior notes, in each case, subject to specified conditions in the Current Credit Agreement (including pro forma compliance with the secured debt to EBITDA ratio and interest coverage ratio described below), which include that the borrowing base shall be reduced by an amount equal to (i) (A)in the case of new senior notes, 25% of the stated principal amount of such senior notes and (B) in the case of refinancing senior notes, 25% of the portion of the new debt that exceeds the original principal amount of the senior notes being refinanced or (ii) in the sole discretion of the lenders holding at least 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Current Credit Agreement prior to the issuance of the senior notes or new debt, a lesser amount. In addition, Legacy must prepay any amount outstanding under the Current Credit Agreement in excess of the redetermined borrowing base upon such a

reduction.

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We may elect that borrowings be comprised entirely of alternate base rate (ABR) loans or Eurodollar loans. Interest on the loans is determined as follows:

- with respect to ABR loans, the alternate base rate equals the highest of the prime rate, the Federal funds effective rate plus 0.50%, or the one-month London interbank rate ("LIBOR") plus 1.00%, plus an applicable margin ranging from and including 0.50% and 1.50% per annum, determined by the percentage of the borrowing base then in effect that is drawn, or
- with respect to any Eurodollar loans, one-, two-, three- or six-month LIBOR plus an applicable margin ranging from and including 1.50% and 2.50% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

We pay a commitment fee equal ranging from and including 0.375% and 0.50% per annum on the average daily amount of the unused amount of the commitments under the Current Credit Agreement, payable quarterly.

Interest is generally payable quarterly for ABR loans and on the last day of the applicable interest period for any Eurodollar loans.

Our Current Credit Agreement also contains various covenants that limit our ability to:

- incur indebtedness;
- enter into certain leases;
- grant certain liens;
- enter into certain derivatives;
- make certain loans, acquisitions, capital expenditures and investments;
- make distributions other than from available cash;
- merge, consolidate or allow any material change in the character of our business; or
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

Our Current Credit Agreement also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- secured debt as of the last day of the most recent quarter to EBITDA (as defined in the Current Credit Agreement) in total over the last four quarters of not more than 2.5 to 1.0;
- as of the last day of the most recent quarter, total EBITDA over the last four quarters to total Interest Expense over the last four quarters to be greater than 2.5 to 1.0; and
- consolidated current assets, as of the last day of the most recent quarter and including the unused amount of the total commitments, to consolidated current liabilities as of the last day of the most recent quarter of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC 815, which includes the current portion of oil, natural gas and interest rate derivatives.

If an event of default exists under our Current Credit Agreement, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. Each of the following would be an event of default:

- failure to pay any principal when due or any reimbursement amount, interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants or conditions contained in the Current Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;

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- default by us on the payment of any other indebtedness in excess of $15.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or any of our subsidiaries;
- the loan documents cease to be in full force and effect;
- our failing to create a valid lien, except in limited circumstances;
- a change of control, which will occur upon (i) the acquisition by any person or group of persons of beneficial ownership of more than 35% of the aggregate ordinary voting power of our equity securities, (ii) the first day on which a majority of the members of the board of directors of our general partner are not continuing directors (which is generally defined to mean members of our board of directors as of April 1, 2014 and persons who are nominated for election or elected to our general partner's board of directors with the approval of a majority of the continuing directors who were members of such board of directors at the time of such nomination or election), (iii) the direct or indirect sale, transfer or other disposition in one or a series of related transactions of all or substantially all of the properties or assets (including equity interests of subsidiaries) of us and our subsidiaries to any person, (iv) the adoption of a plan related to our liquidation or dissolution or (v) Legacy Reserves GP, LLC's ceasing to be our sole general partner;
- the entry of, and failure to pay, one or more adverse judgments in excess of $15.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and
- specified ERISA events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.0 million in any year.

As of December 31, 2014, Legacy was in compliance with all financial and other covenants of the Current Credit Agreement.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

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

	Obligations Due in Period				
Contractual Cash Obligations	2015	2016-2017	2018-2019	Thereafter	Total
	(In thousands)				
Long-term debt					
Revolving credit facility(a)	$—	$—	$109,000	$—	$109,000
Interest on revolving credit facility(b)	2,311	4,622	2,881	—	9,814
Senior Notes	—	—	—	850,000	850,000
Interest on Senior Notes	60,438	120,875	120,875	96,875	399,063
Derivative obligations(c)	2,080	—	—	—	2,080
Management compensation(d)	2,125	4,250	4,250	—	10,625
Asset retirement obligation(e)	3,028	39,932	8,981	174,584	226,525
CO2 purchase commitment(f)	3,908	15,381	18,292	23,981	61,562
Office lease	901	2,215	2,203	854	6,173
Total contractual cash obligations	$74,791	$187,275	$266,482	$1,146,294	$1,674,842

(a) Represents amounts outstanding under our revolving credit facility as of December 31, 2014.

(b) Based upon our weighted average interest rate of 2.12% under our revolving credit facility as of December 31, 2014.

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(c) Derivative obligations represent net liabilities for commodity and interest rate derivatives that were valued as of December 31, 2014, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read "Item 7A. Quantitative and Qualitative Disclosure about Market Risk" for additional information regarding our derivative obligations.

(d) The related employment agreements do not contain termination provisions; therefore, the ultimate payment obligation is not known. For purposes of this table, management has not reflected payments subsequent to 2019.

(e) Asset retirement obligations of oil and natural gas assets, excluding salvage value and accretion, the ultimate settlement and timing of which cannot be precisely determined in advance.

(f) Represents the value of the minimum volume of CO2 required to be purchased in the respective annual period. As the contract price per Mcf of CO2 is based on NYMEX WTI price on the date of purchase, we have assumed the NYMEX WTI strip price as of December 31, 2014.

Critical Accounting Policies and Estimates

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

- it requires assumptions to be made that were uncertain at the time the estimate was made, and
- changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated results of operations or financial condition.

Please read Note 1 of the Notes to Consolidated Financial Statements for a detailed discussion of all significant accounting policies that we employ and related estimates made by management.

Nature of Critical Estimate Item: Oil and Natural Gas Reserves — Our estimate of proved reserves is based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. LaRoche prepares a reserve and economic evaluation of all our properties in accordance with Securities and Exchange Commission, or "SEC," guidelines on a lease, unit or well-by-well basis, depending on the availability of well-level production data. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. In addition, we must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the economics of producing the reserves may change and therefore the estimate of proved reserves also may change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion rates are made concurrently with changes to reserve estimates.

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Assumptions/Approach Used: Units-of-production method to deplete our oil and natural gas properties — The quantity of reserves could significantly impact our depletion expense. Any reduction in proved reserves without a corresponding reduction in capitalized costs will increase the depletion rate.

Effect if Different Assumptions Used: Units-of-production method to deplete our oil and natural gas properties — A 10% increase or decrease in reserves would have decreased or increased, respectively, our depletion expense for the year ended December 31, 2014 by approximately 10%.

Nature of Critical Estimate Item: Asset Retirement Obligations — We have certain obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. US GAAP requires us to estimate asset retirement costs for all of our assets, adjust those costs for inflation to the forecast abandonment date, discount that amount using a credit-adjusted-risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an asset retirement obligation ("ARO") liability in that amount with a corresponding addition to our asset value. When new obligations are incurred, i.e. a new well is drilled or acquired, we add a layer to the ARO liability. We then accrete the liability layers quarterly using the applicable effective credit-adjusted-risk-free rate for each layer. Should either the estimated life or the estimated abandonment costs of a property change materially upon our periodic review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted-risk-free rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost. When well obligations are relieved by sale of the property or plugging and abandoning the well, the related liability and asset costs are removed from our balance sheet. Any difference in the cost to plug and the related liability is recorded as a gain or loss on our income statement in the disposal of assets line item.

Assumptions/Approach Used: Estimating the future asset removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the estimate of the present value calculation of our AROs are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted-risk-free rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments.

Effect if Different Assumptions Used: Since there are so many variables in estimating AROs, we attempt to limit the impact of management’s judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. Unless we expect a well’s plugging to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of a discount factor and present value calculation, could differ from actual results, despite our efforts to make an accurate estimate. We engage independent engineering firms to evaluate our properties annually. We consider the remaining estimated useful life from the year-end reserve report prepared by our independent reserve engineers in estimating when abandonment could be expected for each property. On an annual basis we evaluate our latest estimates against actual abandonment costs incurred.

Nature of Critical Estimate Item: Derivative Instruments and Hedging Activities — We use derivative financial instruments to achieve a more predictable cash flow from our oil and natural gas production and interest expense by reducing our exposure to price fluctuations and interest rate changes. Currently, these transactions are swaps, enhanced swaps and collars whereby we exchange our floating price for our oil and natural gas for a fixed price and floating interest rates for fixed rates with qualified and creditworthy counterparties. The contracts with our counterparties enable us to avoid margin calls for out-of-the-money positions.

We do not specifically designate derivative instruments as cash flow hedges, even though they reduce our exposure to changes in oil and natural gas prices and interest rate changes. Therefore, the mark-to-market of these instruments is recorded in current earnings. We estimate market values utilizing software provided by a third party firm, which specializes in valuing derivatives, and validate these estimates by comparison to counterparty estimates as the basis for these end-of-period mark-to-market adjustments. In order to estimate market values, we

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use forward commodity price curves, if available, or estimates of forward curves provided by third party pricing experts. For our interest rate swaps, we use a yield curve based on money market rates and interest swap rates to estimate market value. When we record a mark-to-market adjustment resulting in a gain or loss in a current period, this change in fair value represents a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods. As shown in the previous tables, we have hedged a significant portion of our future production through 2018. Taking into account the mark-to-market liabilities and assets recorded as of December 31, 2014, the future cash obligations table presented above shows the amounts which we would expect to pay the counterparties over the time periods shown. As oil and gas prices rise and fall, our future cash obligations related to these derivatives will rise and fall.

Nature of Critical Estimate Item: Oil and Natural Gas Property Impairments — Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management’s expectations of future oil and natural gas prices. These future price scenarios reflect Legacy’s estimation of future price volatility. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, using estimated discounted future net cash flows. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in Legacy's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices.

Recently Issued Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the criteria for reporting discontinued operations while enhancing disclosures in this area and is effective for annual and interim periods beginning after December 15, 2014. The provisions of ASU 2014-08 did not have any impact on our financial position or results of operations.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP. The standard is effective for annual periods beginning after December 15, 2016, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We are currently evaluating the impact of our pending adoption of ASU 2014-09 on our consolidated financial statements and have not yet determined the method by which we will adopt the standard in 2017.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from

adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

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Commodity Price Risk

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

We periodically enter into and anticipate entering into derivative arrangements with respect to a portion of our projected oil and natural gas production through various transactions that offset changes in the future prices received. These transactions may include swaps, enhanced swaps and three-way collars. These derivative activities are intended to support oil and natural gas prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

As of December 31, 2014, the fair market value of Legacy's commodity derivative positions was a net asset of $153.1 million. As of December 31, 2013, the fair market value of Legacy's commodity derivative positions was a net asset of $17.7 million. We routinely monitor the credit default risk of our counterparties via risk monitoring services. For more discussion about our derivative transactions and to see a table listing the oil and natural gas derivatives for 2015 through December 31, 2018, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Investing Activities."

If oil prices decline by $1.00 per Bbl, then the standardized measure of our combined proved reserves as of December 31, 2014 would decline from $1,754.6 million to $1,727.2 million, or 1.6%. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of our combined proved reserves as of December 31, 2014 would decline from $1,754.6 million to $1,734.5 million, or 1.1%. However, larger decreases in oil and natural gas prices, such as the recent drop in oil prices, may have a disproportionate impact on our standardized measure.

Interest Rate Risks

At December 31, 2014, Legacy had debt outstanding under the revolving credit facility of $109 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by Legacy for the year ended December 31, 2014 on its floating rate borrowings was 3.05%. A 1% increase in LIBOR on Legacy's outstanding floating rate debt as of December 31, 2014 would result in an estimated $0.1 million increase in annual interest expense as Legacy has entered into interest rate swaps to mitigate the volatility of interest rates, that expire between October and November 2015, on $104 million of floating rate debt with a weighted-average fixed rate of 2.81%. It is never management's intention to hold or issue derivative instruments for speculative trading purposes. Conditions sometimes arise where actual borrowings are less than notional amounts hedged which has and could result in overhedged amounts.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated Financial Statements and supplementary financial data are included in this annual report on Form 10-K beginning on page F-3.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended, or the "Exchange Act") that are designed to ensure that information required to be disclosed in Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our general partner's Chief Executive Officer and Chief Financial

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Officer, as appropriate, to allow timely decisions regarding required disclosure. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

Our management, with the participation of our general partner's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2014. Based upon that evaluation and subject to the foregoing, our general partner's Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures provide reasonable assurance that such controls and procedures were effective to accomplish their objectives.

Our general partner's Chief Executive Officer and Chief Financial Officer do not expect that our disclosure controls or our internal controls will prevent all error and all fraud. The design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be considered relative to their cost. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that we have detected all of our control issues and all instances of fraud, if any. The design of any system of controls also is based partly on certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving our stated goals under all potential future conditions.

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

Management's Annual Report on Internal Control over Financial Reporting

Legacy's management is responsible for establishing and maintaining adequate control over financial reporting. Our internal control over financial reporting is a process designed by, or under the supervision of, our general partner's Chief Executive Officer and Chief Financial Officer, and effected by the board of directors of our general partner, management and other personnel, 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. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of management and the board of directors of our general partner; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisitions, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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 and procedures may deteriorate.

As of December 31, 2014, management assessed the effectiveness of Legacy's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework (2013)," issued by the Committee of Sponsoring Organizations of the Treadway Commission. This assessment included design effectiveness and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on that assessment, management determined that Legacy maintained effective internal control over financial reporting as of December 31, 2014, based on those criteria.

BDO USA, LLP, the independent registered public accounting firm who also audited our Consolidated Financial Statements included in this Annual Report on Form 10-K, has issued an attestation report on our internal control over financial reporting as of December 31, 2014, which is set forth below under "Attestation Report."

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Attestation Report

Report of Independent Registered Public Accounting Firm

Board of Directors and Unitholders
Legacy Reserves LP
Midland, Texas

We have audited Legacy Reserves LP's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Legacy Reserves LP's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Item 9A. Controls and Procedures - Management's Annual Report on Internal Control Over Financial Reporting." Our responsibility is to express an opinion on Legacy Reserves LP's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Legacy Reserves LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Legacy Reserves LP as of December 31, 2014 and 2013, and the related consolidated statements of operations, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2014, and our report dated February 27, 2015 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
February 27, 2015

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ITEM 9B. OTHER INFORMATION

On February 23, 2015, Legacy entered into the Fourth Amendment to the Current Credit Agreement (the "Fourth Amendment"). Pursuant to the Fourth Amendment, the borrowing base under the Current Credit Agreement was decreased from $950 million to $700 million. As of February 23, 2015, Legacy had approximately $130 million drawn under the Current Credit Agreement, leaving approximately $569.9 million of current availability. Pursuant to the Fourth Amendment, the specific ratios or conditions Legacy is now required to maintain have been amended in their entirety to the following:

- secured debt as of the last day of the most recent quarter to EBITDA (as defined in the Current Credit Agreement) in total over the last four quarters of not more than 2.5 to 1.0;
- as of the last day of the most recent quarter, total EBITDA over the last four quarters to total Interest Expense over the last four quarters to be greater than 2.5 to 1.0; and
- consolidated current assets, as of the last day of the most recent quarter and including the unused amount of the total commitments, to consolidated current liabilities as of the last day of the most recent quarter of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC 815, which includes the current portion of oil, natural gas and interest rate derivatives.

The foregoing description of the Fourth Amendment is qualified in its entirety by reference to the full text of the Fourth Amendment, which is filed as Exhibit 10.12 to this Form 10-K.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

We intend to include the information required by this Item 10 in Legacy's definitive proxy statement for its 2015 annual meeting of unitholders under the headings "Election of Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2014.

ITEM 11. EXECUTIVE COMPENSATION

We intend to include information with respect to executive compensation in Legacy's definitive proxy statement for its 2015 annual meeting of unitholders under the heading "Executive Compensation," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2014.

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

We intend to include information regarding Legacy's securities authorized for issuance under equity compensation plans and ownership of Legacy's outstanding securities in Legacy's definitive proxy statement for its 2015 annual meeting of unitholders under the headings "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management," respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2014.

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

We intend to include the information regarding related party transactions in Legacy's definitive proxy statement for its 2015 annual meeting of unitholders under the headings "Corporate Governance" and "Certain Relationships and Related Transactions," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2014.

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ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

We intend to include information regarding principal accountant fees and services in Legacy's definitive proxy statement for its 2015 annual meeting of unitholders under the heading "Independent Registered Public Accounting Firm," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2014.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a)(1) and (2) Financial Statements

The consolidated financial statements of Legacy Reserves LP are listed on the Index to Financial Statements to this annual report on Form 10-K beginning on page F-1.

(a)(3) Exhibits

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

Exhibit Number		Description
3.1	—	Certificate of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.1)
3.2	—	Fourth Amended and Restated Agreement of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed on June 17, 2014, Exhibit 31.)
3.3	—	Certificate of Formation of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.3)
3.4	—	Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)
3.5	—	First Amendment to Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed on May 4, 2012, Exhibit 3.6)
3.6	—	Second Amendment to Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC. (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed on May 4, 2012, Exhibit 3.7)
4.1	—	Registration Rights Agreement dated June 29, 2006, between Henry Holdings LP and Legacy Reserves LP and Legacy Reserves GP, LLC (the "Henry Registration Rights Agreement") (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.2)
4.2	—	Registration Rights Agreement dated March 15, 2006, by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (the "Founders Registration Rights Agreement") (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.3)
4.3	—	Registration Rights Agreement dated April 16, 2007, by and among Nielson & Associates, Inc., Legacy Reserves GP, LLC and Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed May 14, 2007, Exhibit 4.4)

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Exhibit Number		Description
4.4	—	Indenture, dated as of December 4, 2012, among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (including form of the 8% senior notes due 2020) (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed December 10, 2012, Exhibit 4.1)
4.5	—	Indenture, dated as of May 28, 2013, among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (including form of 6.625% senior notes due 2021) (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed May 31, 2013, Exhibit 4.1)
10.1	—	Second Amended and Restated Credit Agreement dated as of March 10, 2011 among Legacy Reserves LP, as borrower, BNP Paribas, as administrative agent, Wells Fargo Bank, N.A., as syndication agent, Compass Bank, as documentation agent, and the Lenders party thereto (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed March 17, 2011, Exhibit 10.1)
10.2	—	First Amendment to Second Amended and Restated Credit Agreement among Legacy Reserves LP, as borrower, the Guarantors, BNP Paribas, as administrative agent, and the Lenders Signatory Hereto dated as of September 30, 2011(Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed November 4, 2011, Exhibit 10.1)
10.3	—	Second Amendment to Second Amended and Restated Credit Agreement Among Legacy Reserves LP, as Borrowers, the Guarantors, BNP Paribas as Adminstrative Agent, and The Lenders Signatory Thereto dated as of March 30, 2012. (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed May 4, 2012, Exhibit 10.1)
10.4	—	Third Amendment to Second Restated and Amended Credit Agreement among Legacy Reserves LP, as borrower, the Guarantors, Wells Fargo Bank National Association, as administrative agent, and the Lenders Signatory thereto dated September 28, 2012 (Incorporated by reference to Legacy Reserves LP's annual report on Form 10-K (File No. 001-33249) filed February 27, 2013, Exhibit 10.4)
10.5	—	Waiver letter among Legacy Reserves LP, Wells Fargo Bank, National Association, as Administrative Agent, and the lenders signatory thereto dated November 14, 2012 (Incorporated by reference to Legacy Reserves LP's annual report on Form 10-K (File No. 001-33249) filed February 27, 2013, Exhibit 10.5)
10.6	—	Fourth Amendment to Second Restated and Amended Credit Agreement among Legacy Reserves LP, as borrower, the Guarantors, Wells Fargo Bank, National Association, as administrative agent, and the Lenders Signatory thereto dated December 20, 2012 (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed December 24, 2012, Exhibit 10.1)
10.7	—	Fifth Amendment to Second Amended and Restated Credit Agreement, dated May 15, 2013, by and between Legacy Reserves LP, Wells Fargo Bank, National Association, as administrative agent, and certain other financial institutions party thereto as Lenders (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed August 7, 2013, Exhibit 10.1)
10.8	—	Third Amended and Restated Credit Agreement, among Legacy Reserves LP, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, Compass Bank, as Syndication Agent, UBS Securities LLC and U.S. Bank National Association, as Co-Documentation Agents and the Lenders Party thereto, dated as of April 1, 2014 (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed April 2, 2014, Exhibit 10.1)
10.9	—	

First Amendment to Third Amended and Restated Credit Agreement, dated April 17, 2014, by and between Legacy Reserves LP, Wells Fargo Bank, National Association, as administrative agent and certain other financial institutions party thereto as lenders (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed October 31, 2014, Exhibit 10.1)

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Exhibit Number		Description
10.10	—	Second Amendment to Third Amended and Restated Credit Agreement, dated May 22, 2014, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association as administrative agent, and the lenders signatory thereto (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed May 28, 2014, Exhibit 10.1)
10.11*	—	Third Amendment to Third Amended and Restated Credit Agreement, dated December 29, 2014, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto
10.12*	—	Fourth Amendment to Third Amended and Restated Credit Agreement, dated February 23, 2015, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto
10.13†	—	Amended and Restated Legacy Reserves LP Long-Term Incentive Plan effective as of August 17, 2007 (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed August 23, 2007, Exhibit 10.1)
10.14†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Restricted Unit Grant Agreement (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.6)
10.15†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Unit Option Grant Agreement (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.7)
10.16†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Unit Grant Agreement (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.8)
10.17†	—	Employment Agreement dated as of March 15, 2006, between Cary D. Brown and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333- 134056) filed May 12, 2006, Exhibit 10.9)
10.18†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Cary D. Brown and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed December 31, 2008, Exhibit 10.1)
10.19†	—	Employment Agreement dated as of March 15, 2006, between Kyle A. McGraw and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.11)
10.20†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Kyle A. McGraw and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed December 31, 2008, Exhibit 10.3)
10.21†	—	Employment Agreement dated as of March 15, 2006, between Paul T. Horne and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333- 134056) filed May 12, 2006, Exhibit 10.12)
10.22†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Paul T. Horne and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed December 31, 2008, Exhibit 10.4)
10.23†	—	Employment Agreement effective April 1, 2012 between Micah C. Foster and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed April 25, 2012, Exhibit 10.1)

10.24†	—	Employment Agreement effective May 1, 2012 between Dan G. LeRoy and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed August 3, 2012, Exhibit 10.3)

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Exhibit Number		Description
10.25†	—	Employment Agreement effective September 24, 2012 between James Daniel Westcott and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed October 31, 2012, Exhibit 10.1)
10.26†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Objective) (Incorporated by reference to Legacy Reserves LP's annual report on Form 10-K (File No. 001-33249) filed on February 21, 2014, Exhibit 10.25)
10.27†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Subjective) (Incorporated by reference to Legacy Reserves LP's annual report on Form 10-K (File No. 001-33249) filed on February 21, 2014, Exhibit 10.26)
10.28	—	Purchase and Sale Agreement, by and between WPX Energy Rocky Mountain, LLC, Legacy Reserves Operating LP, Legacy Reserves GP, LLC and Legacy Reserves LP (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K), dated May 2, 2014 (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed May 6, 2014, Exhibit 2.1)
10.29	—	IDR Holders Agreement, dated June 4, 2014, by and between Legacy Reserves LP and WPX Rocky Mountain, LLC (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed June 4, 2014, Exhibit 10.1)
21.1*	—	List of subsidiaries of Legacy Reserves LP
23.1*	—	Consent of BDO USA, LLP
23.2*	—	Consent of LaRoche Petroleum Consultants, Ltd.
31.1*	—	Rule 13a-14(a) Certification of CEO (under Section 302 of the Sarbanes-Oxley Act of 2002)
31.2*	—	Rule 13a-14(a) Certification of CFO (under Section 302 of the Sarbanes-Oxley Act of 2002)
32.1*	—	Section 1350 Certifications (under Section 906 of the Sarbanes-Oxley Act of 2002)
99.1*	—	Summary Reserve Report from LaRoche Petroleum Consultants, Ltd.
101.INS*	—	XBRL Instance Document
101.SCH*	—	XBRL Taxonomy Extension Schema Document
101.DEF*	—	XBRL Taxonomy Extension Definition Linkbase Document
101.PRE*	—	XBRL Taxonomy Extension Presentation Linkbase Document
101.CAL*	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB*	—	XBRL Taxonomy Extension Label Linkbase Document

* Filed herewith

† Management contract or compensatory plan or arrangement

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this annual report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, on the 27th day of February, 2015.

LEGACY RESERVES LP

By: LEGACY RESERVES GP, LLC,
its general partner

By: /S/ JAMES DANIEL WESTCOTT
Name: James Daniel Westcott
Title: Executive Vice President and Chief Financial Officer (Principal Financial Officer)

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Cary D. Brown and James Daniel Westcott, or either of them, each with power to act without the other, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all subsequent amendments and supplements to this Annual Report on Form 10-K, and to file the same, or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby qualifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this annual report on Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/S/ CARY D. BROWN Cary D. Brown	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	February 27, 2015
/S/ JAMES DANIEL WESTCOTT James Daniel Westcott	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2015
/S/ MICAH C. FOSTER Micah C. Foster	Chief Accounting Officer and Controller (Principal Accounting Officer)	February 27, 2015
/S/ KYLE A. MCGRAW Kyle A. McGraw	Executive Vice President, Chief Development Officer and Director	February 27, 2015
/S/ PAUL T. HORNE Paul T. Horne	Executive Vice President, Chief Operating Officer and Director	February 27, 2015

/S/ DALE A. BROWN Dale A. Brown	Director	February 27, 2015
/S/ WILLIAM R. GRANBERRY William R. Granberry	Director	February 27, 2015
/S/ G. LARRY LAWRENCE G. Larry Lawrence	Director	February 27, 2015
/S/ WILLIAM D. SULLIVAN William D. Sullivan	Director	February 27, 2015
/S/ KYLE D. VANN Kyle D. Vann	Director	February 27, 2015

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Report of Independent Registered Public Accounting Firm

Board of Directors and Unitholders
Legacy Reserves LP
Midland, Texas

We have audited the accompanying consolidated balance sheets of Legacy Reserves LP as of December 31, 2014 and 2013 and the related consolidated statements of operations, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of Legacy Reserves LP's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Legacy Reserves LP at December 31, 2014 and 2013 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Legacy Reserves LP's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2015 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
February 27, 2015

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LEGACY RESERVES LP

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2014 AND 2013

	2014	2013
	(In thousands)	
ASSETS		
Current assets:		
Cash	$725	$2,584
Accounts receivable, net:		
Oil and natural gas	49,390	47,429
Joint interest owners	16,235	16,532
Other	237	626
Fair value of derivatives (Notes 8 and 9)	120,305	3,801
Prepaid expenses and other current assets	5,362	3,727
Total current assets	192,254	74,699
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties using the successful efforts method of accounting	2,946,820	2,265,788
Unproved properties	47,613	58,392
Accumulated depletion, depreciation, amortization and impairment	(1,354,459)	(788,751)
	1,639,974	1,535,429
Other property and equipment, net of accumulated depreciation and amortization of $7,446 and $6,053, respectively	3,767	3,688
Operating rights, net of amortization of $4,509 and $4,024, respectively	2,508	2,992
Fair value of derivatives (Notes 8 and 9)	32,794	21,292
Other assets, net of amortization of $12,551 and $10,097, respectively	24,255	17,641
Investments in equity method investees	3,054	4,092
Total assets	$1,898,606	$1,659,833
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	$2,787	$6,016
Accrued oil and natural gas liabilities (Note 1)	78,615	63,161
Fair value of derivatives (Notes 8 and 9)	2,080	10,060
Asset retirement obligation (Note 11)	3,028	2,610
Other (Notes 8 and 13)	11,066	12,043
Total current liabilities	97,576	93,890
Long-term debt (Note 3)	938,876	878,693
Asset retirement obligation (Note 11)	223,497	173,176
Fair value of derivatives (Notes 8 and 9)	—	2,119
Other long-term liabilities	1,452	1,559
Total liabilities	1,261,401	1,149,437
Commitments and contingencies (Note 6)		
Partners' equity:		
Series A Preferred equity - 2,300,000 units issued and outstanding at December 31, 2014	55,192	—
Series B Preferred equity - 7,200,000 units issued and outstanding at December 31, 2014	174,261	—
Incentive distribution equity - 100,000 units issued and outstanding at December 31, 2014	30,814	—
Limited partners' equity - 68,910,784 and 57,280,049 units issued and outstanding at December 31, 2014 and 2013, respectively	376,885	510,322

General partner's equity (approximately 0.03%)	53	74
Total partners' equity	637,205	510,396
Total liabilities and partners' equity	$1,898,606	$1,659,833

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

	2014	2013	2012
	(In thousands, except per unit data)		
Revenues:			
Oil sales	$396,774	$405,536	$286,254
Natural gas liquids (NGL) sales	27,483	14,095	14,592
Natural gas sales	108,042	65,858	45,614
Total revenues	532,299	485,489	346,460
Expenses:			
Oil and natural gas production	198,801	154,679	112,951
Production and other taxes	31,534	29,508	20,778
General and administrative	38,980	28,907	24,526
Depletion, depreciation, amortization and accretion	173,686	158,415	102,144
Impairment of long-lived assets	448,714	85,757	37,066
(Gain) loss on disposal of assets	(2,479)	579	(2,496)
Total expenses	889,236	457,845	294,969
Operating income (loss)	(356,937)	27,644	51,491
Other income (expense):			
Interest income	873	776	16
Interest expense (Notes 3, 8 and 9)	(67,218)	(50,089)	(20,260)
Equity in income of equity method investees	428	559	111
Net gains (losses) on commodity derivatives (Notes 8 and 9)	138,092	(13,531)	38,493
Other	258	18	(118)
Income (loss) before income taxes	(284,504)	(34,623)	69,733
Income tax (expense) benefit	859	(649)	(1,096)
Net income (loss)	$(283,645)	$(35,272)	$68,637
Distributions to preferred unitholders	(11,694)	—	—
Net income (loss) attributable to unitholders	$(295,339)	$(35,272)	$68,637
Income (loss) per unit — basic and diluted (Note 12)	$(4.92)	$(0.62)	$1.40
Weighted average number of units used in computing income (loss) per unit —			
Basic	60,053	57,220	48,991
Diluted	60,053	57,220	48,991

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

	Series A Preferred Equity		Series B Preferred Equity		Incentive Distribution Equity		Unitholders' Equity			
	Units	Amount	Units	Amount	Units	Amount	Limited Partner Units	Limited Partner Amount	General Partner Amount	Total Partners' Equity
	(In thousands)									
Balance, December 31, 2011	—	$—	—	$—	—	$—	47,802	$488,264	$71	$488,335
Units issued for services	—	—	—	—	—	—	20	568	—	568
Unit-based compensation	—	—	—	—	—	—	—	1,762	—	1,762
Vesting of restricted units	—	—	—	—	—	—	47	—	—	—
Net proceeds from equity offering	—	—	—	—	—	—	9,170	217,998	—	217,998
Units issued in exchange for oil and natural gas properties	—	—	—	—	—	—	—	—	—	—
Distributions to unitholders, $2.23 per unit	—	—	—	—	—	—	—	(107,020)	—	(107,020)
Net income	—	—	—	—	—	—	—	68,611	26	68,637
Balance, December 31, 2012	—	—	—	—	—	—	57,039	670,183	97	670,280
Units issued to Legacy Board of Directors for services	—	—	—	—	—	—	18	509	—	509
Unit-based compensation	—	—	—	—	—	—	—	3,582	—	3,582
Vesting of restricted units	—	—	—	—	—	—	70	—	—	—
Offering costs associated with the issuance of units	—	—	—	—	—	—	—	(25)	—	(25)
Units issued in exchange for investment in equity method	—	—	—	—	—	—	153	4,001	—	4,001

investee										
Redemption of general partner interest	—	—	—	—	—	—	—	—	(12)	(12)
Distributions to unitholders, $2.31 per unit	—	—	—	—	—	—	—	(132,667)	—	(132,667)
Net loss	—	—	—	—	—	—	—	(35,261)	(11)	(35,272)
Balance, December 31, 2013	—	—	—	—	—	—	57,280	510,322	74	510,396
Units issued to Legacy Board of Directors for services	—	—	—	—	—	—	18	499	—	499
Issuance of preferred units, net	2,300	55,192	7,200	174,261	—	—	—	—	—	229,453
Unit-based compensation	—	—	—	—	—	—	—	3,797	—	3,797
Vesting of restricted and phantom units	—	—	—	—	—	—	113	—	—	—
Issuance of units, net	—	—	—	—	—	—	11,500	303,457	—	303,457
Incentive Distribution Units issued in exchange for oil and natural gas properties	—	—	—	—	100	30,814	—	—	—	30,814
Distributions to preferred unitholders	—	—	—	—	—	—	—	(11,694)	—	(11,694)
Distributions to unitholders, $2.405 per unit	—	—	—	—	—	—	—	(145,872)	—	(145,872)
Net income	—	—	—	—	—	—	—	(283,624)	(21)	(283,645)
Balance, December 31, 2014	2,300	$55,192	7,200	$174,261	100	$30,814	68,911	$376,885	$53	$637,205

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

	2014	2013	2012
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$(283,645)	$(35,272)	$68,637
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	173,686	158,415	102,144
Amortization of debt discount and issuance costs	4,637	3,780	1,626
Impairment of long-lived assets	448,714	85,757	37,066
(Gains) losses on derivatives	(140,771)	8,743	(40,999)
Equity in income of equity method investees	(428)	(559)	(111)
Distribution from equity method investee	1,467	861	—
Unit-based compensation	2,089	3,142	26
(Gain) loss on disposal of assets	(2,479)	579	(2,496)
Changes in assets and liabilities:			
Increase in accounts receivable, oil and natural gas	(1,962)	(9,882)	(2,058)
(Increase) decrease in accounts receivable, joint interest owners	297	11,319	(17,552)
(Increase) decrease in accounts receivable, other	389	(75)	(347)
(Increase) decrease in other assets	(1,193)	618	231
Increase (decrease) in accounts payable	(3,228)	4,194	(1,464)
Increase in accrued oil and natural gas liabilities	15,454	12,999	4,811
Increase (decrease) in other liabilities	(5,811)	(3,485)	127
Total adjustments	490,861	276,406	81,004
Net cash provided by operating activities	207,216	241,134	149,641
Cash flows from investing activities:			
Investment in oil and natural gas properties	(638,942)	(202,419)	(702,945)
Proceeds from sale of assets	5,334	2,566	9,780
Investment in other equipment	(1,472)	(2,492)	(1,246)
Goodwill	—	—	(7,770)
Net cash settlements on commodity derivatives	2,666	(7,056)	5,902
Net cash used in investing activities	(632,414)	(209,401)	(696,279)
Cash flows from financing activities:			
Proceeds from long-term debt	1,333,000	802,263	931,784
Payments of long-term debt	(1,275,000)	(701,000)	(493,000)
Payments of debt issuance costs	(10,005)	(1,217)	(2,766)
Proceeds from issuance of limited partner interests, net	532,910	(25)	217,998
Redemption of general partner interest	—	(12)	—
Distributions to unitholders	(157,566)	(132,667)	(107,020)
Net cash provided by (used in) financing activities	423,339	(32,658)	546,996
Net increase (decrease) in cash and cash equivalents	(1,859)	(925)	358
Cash and cash equivalents, beginning of period	2,584	3,509	3,151
Cash and cash equivalents, end of period	$725	$2,584	$3,509
Non-Cash Investing and Financing Activities:			
Asset retirement obligation costs and liabilities	$941	$494	$878
Asset retirement obligations associated with property acquisitions	$50,487	$10,969	$38,857

Asset retirement obligations associated with properties sold	$(5,891)	$(1,606)	$—
Units issued in exchange for investment in equity method investee	$—	$4,001	$—
Incentive Distribution units issued in exchange for oil and natural gas properties	$30,814	$—	$—
Note receivable received in exchange for the sale of oil and natural gas properties	$—	$11,857	$—

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

(a) Organization, Basis of Presentation and Description of Business

Legacy Reserves LP ("LRLP," "Legacy" or the "Partnership") and its affiliated entities are referred to as Legacy in these financial statements.

LRLP, a Delaware limited partnership, was formed by its general partner, Legacy Reserves GP, LLC ("LRGPLLC"), on October 26, 2005 to own and operate oil and natural gas properties. LRGPLLC is a Delaware limited liability company formed on October 26, 2005, and it currently owns an approximately 0.03% general partner interest in LRLP.

Significant information regarding rights of the unitholders includes the following:

- Right to receive distributions of available cash within 45 days after the end of each quarter.
- No limited partner shall have any management power over our business and affairs; the general partner shall conduct, direct and manage LRLP's activities.
- The general partner may be removed if such removal is approved by the unitholders holding at least 66 2/3 percent of the outstanding units, including units held by LRLP's general partner and its affiliates.
- Right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year.

In the event of a liquidation, after making required payments to Legacy's preferred unitholders, all property and cash in excess of that required to discharge all liabilities will be distributed to the unitholders and LRLP's general partner in proportion to their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of Legacy's assets in liquidation.

Legacy owns and operates oil and natural gas producing properties located primarily in the Permian Basin (West Texas and Southeast New Mexico), Rocky Mountain and Mid-Continent regions of the United States. Legacy has acquired oil and natural gas producing properties and drilled and undrilled leasehold.

The accompanying financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred.

(b) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. Legacy routinely assesses the financial strength of its customers. Bad debts are recorded based on an account-by-account review. Accounts are written off after all means of collection have been exhausted and potential recovery is considered remote. Legacy does not have any off-balance-sheet credit exposure related to its customers (see Note 10).

(c) Oil and Natural Gas Properties

Legacy accounts for oil and natural gas properties using the successful efforts method. Under this method of accounting, costs relating to the acquisition and development of proved areas are capitalized when incurred. The costs of development wells are capitalized whether productive or non-productive. Leasehold acquisition costs are

capitalized when incurred. If proved reserves are found on an unproved property, leasehold cost is transferred to proved properties. Exploration dry holes are charged to expense when it is determined that no commercial reserves exist. Other exploration costs, including personnel costs, geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense when incurred. The costs of acquiring or constructing support equipment and facilities used in oil and gas producing activities are capitalized. Production costs are charged to expense as incurred and are those costs incurred to operate and maintain our wells and related equipment and facilities.

Depreciation and depletion of producing oil and natural gas properties is recorded based on units of production. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (wells and related equipment and facilities) are amortized on the basis of proved developed reserves. As more fully described below, proved reserves are estimated annually by Legacy's independent petroleum engineer, LaRoche Petroleum Consultants, Ltd. ("LaRoche"), and are subject to future revisions based on availability of additional information. Legacy's in-house reservoir engineers prepare an updated estimate of reserves each quarter. Depletion is calculated each quarter based upon the latest estimated reserves data available. As discussed in Note 11, asset retirement costs are recognized when the asset is placed in service, and are amortized over proved developed reserves using the units of production method. Asset retirement costs are estimated by Legacy's engineers using existing regulatory requirements and anticipated future inflation rates.

Upon sale or retirement of complete fields of depreciable or depletable property, the book value thereof, less proceeds from sale or salvage value, is charged to income. On sale or retirement of an individual well the proceeds are credited to accumulated depletion and depreciation.

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. These future price scenarios reflect Legacy's estimation of future price volatility. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, using estimated discounted future net cash flows. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in Legacy's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices. For the year ended December 31, 2014, Legacy recognized $448.7 million of impairment expense, $413.3 million of of which was in 250 separate producing fields, due to the significant decline in commodity prices during the year ended December 31, 2014, which decreased the expected future cash flows below the carrying value of the assets. As Legacy has historically grown through the acquisition of oil and natural gas properties, most of which were acquired during higher commodity price environments, the sharp decline in oil and natural gas prices during the latter portion of 2014 resulted in a corresponding decrease in the expected future cash flows of such assets from the date of their acquisition as compared to December 31, 2014. As evidenced above, this decrease was not limited to any one field or area of operation, as it impacted the value of assets across Legacy's portfolio. The remainder of the impairment related primarily to unproven properties. For the year ended December 31, 2013, Legacy recognized $78.0 million of impairment expense on 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 unproven properties acquired since 2010 that were no longer viable. For the year ended December 31, 2012, Legacy recognized $22.8 million of impairment expense on 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.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. During the year ended December 31, 2014, Legacy recognized $35.0 million of impairment of unproven properties.

(d) Oil, NGLs and Natural Gas Reserve Quantities

Legacy's estimates of proved reserves are based on the quantities of oil, NGLs and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. LaRoche prepares a reserve and economic evaluation of all Legacy's properties on a case-by-case basis utilizing information provided to it by Legacy and information available from state agencies that collect information reported to it by the operators of Legacy's properties. The estimates of Legacy's proved reserves have been prepared and presented in accordance with SEC rules and accounting standards.

Reserves and their relation to estimated future net cash flows impact Legacy's depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Legacy prepares its reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firm described above adheres to the same guidelines when preparing the reserve report. The accuracy of Legacy's reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

Legacy's proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil, NGLs and natural gas eventually recovered.

(e) Income Taxes

Legacy is structured as a limited partnership, which is a pass-through entity for United States income tax purposes.

The State of Texas has a margin-based franchise tax law that is commonly referred to as the Texas margin tax and is assessed at a 1% rate. Corporations, limited partnerships, limited liability companies, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the tax. The tax is considered an income tax and is determined by applying a tax rate to a base that considers both revenues and expenses.

Legacy recorded income tax (expense) benefit of $0.9 million, $(0.6) million and $(1.1) million for the years ended December 31, 2014, 2013 and 2012, respectively, which consists primarily of the Texas margin tax and federal income tax on a corporate subsidiary which employs full and part-time personnel providing services to the Partnership. The Partnership's total effective tax rate differs from statutory rates for federal and state purposes primarily due to being structured as a limited partnership, which is a pass-through entity for federal income tax purposes.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. In addition, individual unitholders have different investment bases depending upon the timing and price of acquisition of their common units, and each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in the consolidated financial statements. As a result, the aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as the Partnership does not have access to information about each unitholder's tax attributes in the Partnership. However, with respect to the Partnership, the Partnership's book basis in its net assets exceeds the Partnership's net tax basis by $1.5 billion at December 31, 2014.

(f) Derivative Instruments and Hedging Activities

Legacy uses derivative financial instruments to achieve more predictable cash flows by reducing its exposure to oil, NGL and natural gas price fluctuations and interest rate changes. Legacy does not specifically designate derivative instruments as cash flow hedges, even though they reduce its exposure to changes in oil and natural gas prices and interest rates. Therefore, Legacy records the change in the fair market values of oil, NGL and natural gas derivatives in current earnings. Changes in the fair values of interest rate derivatives are recorded in interest expense (see Notes 8 and 9).

(g) Use of Estimates

Management of Legacy has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ materially from those estimates. Estimates which are particularly significant to the consolidated financial statements include estimates of oil and natural gas reserves, valuation of derivatives, future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations and accrued revenues.

(h) Revenue Recognition

Sales of crude oil, NGLs and natural gas are recognized when the delivery to the purchaser has occurred and title has been transferred. This occurs when oil or natural gas has been delivered to a pipeline or a tank lifting has occurred. Crude oil is priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. Virtually all of Legacy’s natural gas contracts’ pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas, and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. These market indices are determined on a monthly basis. As a result, Legacy’s revenues from the sale of oil and natural gas will suffer if market prices decline and benefit if they increase. Legacy believes that the pricing provisions of its oil and natural gas contracts are customary in the industry.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded as “Accounts receivable - oil and natural gas” in the accompanying consolidated balance sheets.

Legacy uses the “net-back” method of accounting for transportation arrangements of its natural gas sales. Legacy sells natural gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by its purchasers and reflected in the wellhead price. Legacy’s contracts with respect to the sale of its natural gas produced, with one immaterial exception, provide Legacy with a net price payment. That is, when Legacy is paid for its natural gas by its purchasers, Legacy receives a price which is net of any costs incurred for treating, transportation, compression, etc. In accordance with the terms of Legacy’s contracts, the payment statements Legacy receives from its purchasers show a single net price without any detail as to treating, transportation, compression, etc. Thus, Legacy’s revenues are recorded at this single net price.

Natural gas imbalances occur when Legacy sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of its share is treated as a liability. If Legacy receives less than its entitled share, the underproduction is recorded as a receivable. Legacy did not have any significant natural gas

imbalance positions as of December 31, 2014, 2013 and 2012.

Legacy is paid a monthly operating fee for each well it operates for outside owners proportionate to each owner's working interest. The fee covers monthly general and administrative costs. As the operating fee is a reimbursement of costs incurred on behalf of third parties, the fee has been netted against general and administrative expense.

(i) Investments

Undivided interests in oil and natural gas properties owned through joint ventures are consolidated on a proportionate basis. Investments in entities where Legacy exercises significant influence, but not a controlling interest, are accounted for by the equity method. Under the equity method, Legacy’s investments are stated at cost plus the equity in undistributed earnings and losses after acquisition.

(j) Intangible assets

Legacy has capitalized certain operating rights acquired in the acquisition of oil and natural gas properties. The operating rights, which have no residual value, are amortized over their estimated economic life of approximately 15 years beginning July 1, 2006. Amortization expense is included as an element of depletion, depreciation, amortization and accretion expense. Impairment is assessed on a quarterly basis or when there is a material change in the remaining useful life. The expected amortization expenses for 2015, 2016, 2017, 2018 and 2019 are $444,000, $417,000, $396,000, $358,000 and $349,000, respectively.

(k) Environmental

Legacy is subject to extensive federal, state and local environmental laws and regulations. These laws, which are frequently changing, regulate the discharge of materials into the environment and may require Legacy to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation are probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable.

(l) Income (Loss) Per Unit

Basic income (loss) per unit amounts are calculated after deducting distributions paid to Legacy's Preferred Units using the weighted average number of units outstanding during each period. Diluted income (loss) per unit also give effect to dilutive unvested restricted units (calculated based upon the treasury stock method) (see Note 12).

(m) Redemption of Units

Units redeemed are recorded at cost.

(n) Segment Reporting

Legacy’s management initially treats each new acquisition of oil and natural gas properties as a separate operating segment. Legacy aggregates these operating segments into a single segment for reporting purposes.

(o) Unit-Based Compensation

Concurrent with its formation on March 15, 2006, a Long-Term Incentive Plan ("LTIP") for Legacy was created. Due to Legacy's history of cash settlements for option exercises and certain phantom unit awards, Legacy accounts for these awards under the liability method, which requires the Partnership to recognize the fair value of

each unit option at the end of each period. Expense or benefit is recognized as the fair value of the liability changes from period to period. Legacy accounts for executive phantom unit and restricted unit awards under the equity method. Legacy's issued units, as reflected in the accompanying consolidated balance sheet at December 31, 2014, do not include 254,183 units related to unvested restricted unit awards.

(p) Accrued Oil and Natural Gas Liabilities

Below are the components of accrued oil and natural gas liabilities as of December 31, 2014 and 2013.

	December 31,	
	2014	2013
	(In thousands)	
Revenue payable to joint interest owners	$19,267	$21,686
Accrued lease operating expense	21,177	11,914
Accrued capital expenditures	20,773	10,409
Accrued ad valorem tax	9,382	9,459
Other	8,016	9,693
	$78,615	$63,161

(2) Fair Values of Financial Instruments

The estimated fair values of Legacy's financial instruments closely approximate the carrying amounts as discussed below:

Debt. The carrying amount of the revolving long-term debt approximates fair value because Legacy's current borrowing rate does not materially differ from market rates for similar bank borrowings. The fair value of the 8% senior notes due 2020 (the "2020 Senior Notes") and the 6.625% senior notes due 2021 (the "2021 Senior Notes") was $244.5 million and $449.6 million, respectively, as of December 31, 2014. As these valuations are based on unadjusted quoted prices in an active market, the fair values would be classified as Level 1.

Long-term incentive plan obligations. See Note 13 for discussion of process used in estimating the fair value of the long-term incentive plan obligations.

Derivatives. See Note 8 for discussion of process used in estimating the fair value of commodity price and interest rate derivatives.

(3) Long-Term Debt

Long-term debt consists of the following at December 31, 2014 and 2013:

	December 31,	
	2014	2013
	(In thousands)	
Credit Facility due 2019	$109,000	348,000
8% Senior Notes due 2020	300,000	300,000
6.625% Senior Notes due 2021	550,000	250,000
	959,000	898,000

Unamortized discount on Senior Notes	(20,124)	(19,307)
Total long term debt	$938,876	$878,693

Credit Facility

Previous Credit Agreement: On March 10, 2011, Legacy entered into a five-year $1 billion secured revolving credit facility (as amended, the "Previous Credit Agreement"). Borrowings under the Previous Credit Agreement were set to mature on March 10, 2016.

Current Credit Agreement: On April 1, 2014, Legacy entered into a five-year $1.5 billion secured revolving credit facility with Wells Fargo Bank, National Association, as administrative agent (the "Current Credit Agreement") which replaced the Previous Credit Agreement. Borrowings under the Current Credit Agreement mature on April 1, 2019. Legacy's obligations under the Current Credit Agreement are secured by mortgages on over 80% of the total value of its oil and natural gas properties as well as a pledge of all of its ownership interests in its operating subsidiaries. The amount available for borrowing at any one time is limited to the lesser of the borrowing base and the facility amount and contains a $2 million sub-limit for letters of credit. The borrowing base at December 31, 2014 was set at $950 million, but was redetermined on February 23, 2015 pursuant to the Fourth Amendment to the revolving credit facility. Please see Note 15, Subsequent Events for more details. The borrowing base is subject to semi-annual redeterminations on April 1 and October 1 of each year. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. Legacy also has the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of certain oil and natural gas properties where the purchase price is greater than 10% of the borrowing base then in effect. Any increase in the borrowing base requires the consent of all the lenders and any decrease in or maintenance of the borrowing base must be approved by the lenders holding at least 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Current Credit Agreement. If the requisite lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Current Credit Agreement so long as it does not increase the borrowing base then in effect. Under the Current Credit Agreement, interest on debt outstanding is charged based on Legacy's selection of a one-, two-, three- or six-month LIBOR rate plus 1.5% to 2.5%, or the ABR which equals the highest of the prime rate, the Federal funds effective rate plus 0.50% or one-month LIBOR plus 1.00%, plus an applicable margin from 0.5% to 1.5% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

The Current Credit Agreement contains various covenants that limit Legacy's ability to: (i) incur indebtedness, (ii) enter into certain leases, (iii) grant certain liens, (iv) enter into certain swaps, (v) make certain loans, acquisitions, capital expenditures and investments, (vi) make distributions other than from available cash, (vii) merge, consolidate or allow any material change in the character of its business and (viii) engage in certain asset dispositions, including a sale of all or substantially all of its assets. The Current Credit Agreement also contains covenants that, among other things, require Legacy to maintain specified ratios or conditions. As of December 31, 2014 these covenants were as follows: (i) total debt to EBITDA of not more than 4.5 to 1.0 through June 15, 2015 and 4.0 to 1.0 thereafter and (ii) consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under FASB Accounting Standards Codification 815, which includes the current portion of oil, natural gas and interest rate derivatives. These covenants were amended pursuant to the Fourth Amendment to the revolving credit facility. Please see Note 15, Subsequent Events for further details.

As of December 31, 2014, Legacy had outstanding borrowings of $109 million under the Current Credit Agreement at a weighted average interest rate of 2.12%. Thus, Legacy had approximately $840.9 million of borrowing availability remaining. For the year ended December 31, 2014, Legacy paid $8.9 million of interest expense on both the Previous

and Current Credit Agreements.

At December 31, 2014, Legacy was in compliance with all covenants contained in the Current Credit Agreement.

8% Senior Notes Due 2020

On December 4, 2012, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $300 million of our 8% Senior Notes due 2020 (the "2020 Senior Notes"), which were subsequently registered through a public exchange offer that closed on January 8, 2014. The 2020 Senior Notes were issued at 97.848% of par.

Legacy will have the option to redeem the 2020 Senior Notes, in whole or in part, at any time on or after December 1, 2016, at the specified redemption prices set forth below together with any accrued and unpaid interest, if any, to the date of redemption if redeemed during the twelve-month period beginning on December 1 of the years indicated below.

Year	Percentage	
2016	104.000	%
2017	102.000	%
2018	100.000	%

Prior to December 1, 2016, Legacy may redeem all or any part of the 2020 Senior Notes at the “make-whole” redemption price as defined in the indenture. In addition, prior to December 1, 2015, Legacy may at its option, redeem up to 35% of the aggregate principal amount of the 2020 Senior Notes at the redemption price of 108% with the net proceeds of a public or private equity offering. Legacy may be required to offer to repurchase the 2020 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. Legacy and Legacy Reserves Finance Corporation's obligations under the 2020 Senior Notes are guaranteed by its 100% owned subsidiaries Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc. In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the properties of the guarantor; (ii) in connection with any sale or other disposition of sufficient capital stock of the guarantor so that it no longer qualifies as our Restricted Subsidiary (as defined in the indenture); (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance, covenant defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of the guarantor provided no default or event of default has occurred or is occurring; (vi) at such time the guarantor does not have outstanding guarantees of its, or any other guarantor's, other debt; or (vii) upon merging into, or transferring all of its properties to Legacy or another guarantor and ceasing to exist. Refer to Note 14 - Subsidiary Guarantors for further details on Legacy's guarantors.

The indenture governing the 2020 Senior Notes limits Legacy's ability and the ability of certain of its subsidiaries to (i) sell assets; (ii) pay distributions on, repurchase or redeem equity interests or purchase or redeem Legacy's subordinated debt, provided that such subsidiaries may pay dividends to the holders of their equity interests (including Legacy) and Legacy may pay distributions to the holders of its equity interests subject to the absence of certain defaults, the satisfaction of a fixed charge coverage ratio test and so long as the amount of such distributions does not exceed the sum of available cash (as defined in the partnership agreement) at Legacy, net proceeds from the sales of certain securities and return of or reductions to capital from restricted investments; (iii) make certain investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from certain of its subsidiaries to Legacy; (vii) consolidate, merge or transfer all or substantially all of Legacy's assets; (viii) engage in certain transactions with affiliates; (ix) create unrestricted subsidiaries; and (x) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 2020 Senior Notes are rated investment grade by each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indenture) has occurred and is continuing, many of

such covenants will terminate and Legacy and its subsidiaries will cease to be subject to such covenants. The indenture also includes customary events of default. The Partnership is in compliance with all covenants of the 2020 Senior Notes.

Interest is payable on June 1 and December 1 of each year.

6.625% Senior Notes Due 2021

On May 28, 2013, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $250 million of our 6.625% Senior Notes due 2021 (the "2021 Senior Notes"), which were subsequently registered through a public exchange offer that closed on March 18, 2014. The 2021 Senior Notes were issued at 98.405% of par.

On May 13, 2014, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of an additional $300 million of the 6.625% 2021 Senior Notes. These 2021 Senior Notes were issued at 99% of par.

The terms of the 2021 Senior Notes, including details related to our guarantors, are substantially identical to the terms of the 2020 Senior Notes with the exception of the maturity date, interest rate and redemption provisions noted below. Legacy will have the option to redeem the 2021 Senior Notes, in whole or in part, at any time on or after June 1, 2017, at the specified redemption prices set forth below together with any accrued and unpaid interest, if any, to the date of redemption if redeemed during the twelve-month period beginning on June 1 of the years indicated below.

Year	Percentage	
2017	103.313	%
2018	101.656	%
2019 and thereafter	100.000	%

Prior to June 1, 2017, Legacy may redeem all or any part of the 2021 Senior Notes at the “make-whole” redemption price as defined in the indenture. In addition, prior to June 1, 2016, Legacy may at its option, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes at the redemption price of 106.625% with the net proceeds of a public or private equity offering. Legacy may be required to offer to repurchase the 2021 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. The Partnership is in compliance with all covenants of the 2021 Senior Notes.

Interest is payable on June 1 and December 1 of each year.

(4) Acquisitions

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, both 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 with net proceeds from Legacy’s November 2012 public offering of units and the 2020 Senior Notes. The effective date of this purchase was October 1, 2012. The operating results from these COG 2012 Acquisition properties have been included from their acquisition on December 20, 2012.

The allocation of the purchase price to the fair value of the acquired assets and liabilities assumed was as follows (in thousands):

Proved oil and natural gas properties including related equipment	$495,897
Unproved properties	37,994
Total assets	$533,891
Future abandonment costs	(31,274)
Fair value of net assets acquired	$502,617

WPX Acquisition

On June 4, 2014, Legacy purchased a non-operated interest in oil and natural gas properties located in the Piceance Basin in Garfield County, Colorado from WPX Energy Rocky Mountain, LLC , a subsidiary of WPX Energy, Inc., (the "WPX Acquisition") for a net purchase price of $360.0 million. Consideration included both cash and 300,000 Incentive Distribution Units representing limited partner interests in the Partnership (the "Incentive Distribution Units"), 100,000 of which vested immediately and the remainder of which are available to vest and also subject to forfeiture pursuant to the terms of a related Incentive Distribution Unitholder Agreement. This acquisition was accounted for as a business combination. The 100,000 vested Incentive Distribution Units have been reflected in the financial statements at their estimated issuance date fair value of $30.8 million. No value was ascribed to the unvested Incentive Distribution Units upon the closing of the WPX Acquisition as the vesting of the unvested Incentive Distribution Units is dependent upon the consummation of future transactions with WPX and such Incentive Distribution Units will be a portion of the consideration of any such future transactions. During the year ended December 31, 2014, Legacy incurred acquisition costs, recorded in general and administrative expense, of approximately $5.4 million related to the WPX Acquisition and other acquisitions.

The allocation of the WPX Acquisition purchase price to the fair value of the acquired assets and liabilities assumed was as follows (in thousands):

Proved oil and natural gas properties including related equipment	$403,980
Future abandonment costs	(43,989)
Fair value of net assets acquired	$359,991

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the COG 2012 Acquisition had occurred on January 1, 2011 and the WPX Acquisition had occurred on January 1, 2013. The pro forma amounts are not necessarily indicative of the results that may be reported in the future:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Revenues	$569,674	$549,968	$478,115
Net income	$(289,659)	$(50,041)	$97,092
Income (loss) per unit — basic and diluted	$(4.82)	$(0.87)	$1.71
Units used in computing income (loss) per unit:			
Basic	60,053	57,220	56,887

Diluted	60,053	57,220	56,887

The amounts of revenues and revenues in excess of direct operating expenses included in our consolidated statements of operations for the COG 2012 Acquisition and the WPX Acquisition are shown in the table that follows. Direct operating expenses include lease operating expenses and production and other taxes.

	Year Ended December 31,		
	2014	2013	2012
COG 2012 Acquisition	(In thousands)		
Revenues	$96,560	$113,222	$3,693
Excess of revenues over direct operating expenses	$54,320	$73,408	$2,654
WPX Acquisition			
Revenues	$48,470	$—	$—
Excess of revenues over direct operating expenses	$22,333	$—	$—

(5) Related Party Transactions

Cary D. Brown, Legacy's Chairman, President and Chief Executive Officer, and Kyle A. McGraw, Director and Legacy's Executive Vice President and Chief Development Officer, own interests in partnerships which, in turn, own a combined non-controlling 4.16% interest as limited partners in a partnership which, until November 10, 2014, owned the building that Legacy occupies. Monthly rent is $64,841 without respect to property taxes and insurance. The lease expires in September 2020.

During the year ended December 31, 2012, Legacy acquired a 5% working interest in prospective Cline Shale acreage from FireWheel Energy, LLC ("FireWheel"), the operator of the properties, for $7.2 million. During the year ended December 31, 2013, Legacy acquired a 5% working interest in additional acreage from Firewheel for $1.2 million. FireWheel is a private-equity funded oil and natural gas exploration company in which Alan Brown, brother of Cary D. Brown, is a principal. The interests acquired by Legacy were marketed to numerous industry participants and are governed by an industry standard Participation Agreement and Joint Operating Agreement.

(6) Commitments and Contingencies

From time to time Legacy is a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, Legacy is not currently a party to any proceeding that it believes could have a potential material adverse effect on its financial condition, results of operations or cash flows.

Legacy is party to a contractual agreement, extending through 2022, to purchase CO2 volumes from a third party. The contract requires Legacy to purchase minimum annual volumes, the pricing of which is calculated as a percentage of NYMEX-WTI oil prices, with a floor of $57.14. Based upon the minimum required volumes and the NYMEX-WTI strip prices as of December 31, 2014, we estimate the value of our total future obligation to be approximately $61.6 million.

Legacy is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of Legacy could be adversely affected.

Legacy has employment agreements with its officers that specify that if the officer is terminated by Legacy for other than cause or following a change in control, the officer shall receive severance pay ranging from 24 to 36 months salary plus bonus and COBRA benefits, respectively.

(7) Business and Credit Concentrations

Cash

Legacy maintains its cash in bank deposit accounts, which, at times, may exceed federally insured amounts. Legacy has not experienced any losses in such accounts. Legacy believes it is not exposed to any significant credit risk on its cash.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Revenue and Trade Receivables

Substantially all of Legacy's accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact Legacy's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, Legacy has not experienced significant credit losses on such receivables. No bad debt expense was recorded in 2014, 2013 or 2012. Legacy cannot ensure that such losses will not be realized in the future. A listing of oil and natural gas purchasers exceeding 10% of Legacy's sales is presented in Note 10.

Commodity Derivatives

Due to the volatility of oil and natural gas prices, Legacy periodically enters into price-risk management transactions (e.g., swaps, enhanced swaps or three-way collars) for a portion of its oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. Legacy values these transactions at fair value on a recurring basis (Note 8). As of December 31, 2014, Legacy's commodity derivative transactions have a fair value favorable to the Partnership of $153.1 million, collectively. Legacy enters into commodity derivative transactions with members of its revolving credit facility, who Legacy's management believes are major, creditworthy financial institutions. In addition, Legacy reviews and assesses the creditworthiness of these institutions on a routine basis.

(8) Fair Value Measurements

Fair value is defined as the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1:	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Legacy considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
Level 2:	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that Legacy values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps and collars and interest rate swaps as well as long-term incentive plan liabilities calculated using the Black-Scholes model to estimate the fair value as of the measurement date.
Level 3:	Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e. supported by little or no market activity). Legacy's valuation models are primarily industry standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 3 instruments currently are limited to Midland-Cushing crude oil differential swaps. Although Legacy utilizes third party broker quotes to assess the reasonableness of its prices and valuation techniques, Legacy does not have sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

As required by ASC 820-10, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Legacy's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy Legacy's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2014 and 2013:

	Fair Value Measurements Using			
Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of
	(In thousands)			
LTIP liability(a)	$—	$(11)	$—	$(11)
Oil and natural gas derivatives	—	152,544	555	153,099
Interest rate swaps	—	(2,080)	—	(2,080)
Total as of December 31, 2014	$—	$150,453	$555	$151,008
LTIP liability(a)	$—	$(2,217)	$—	$(2,217)
Oil and natural gas derivatives	—	(2,942)	20,615	17,673
Interest rate swaps	—	(4,759)	—	(4,759)
Total as of December 31, 2013	$—	$(9,918)	$20,615	$10,697

(a) See Note 13 for further discussion on unit-based compensation expenses related to the LTIP liability for certain grants accounted for under the liability method and included in other current liabilities in the accompanying consolidated balance sheet.

Legacy estimates the fair values of the swaps based on published forward commodity price curves for the underlying commodities as of the date of the estimate for those commodities for which published forward pricing is readily available. For those commodity derivatives for which forward commodity price curves are not readily available, Legacy estimates, with the assistance of third-party pricing experts, the forward curves as of the date of the estimate. Legacy validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming, where applicable, that those securities trade in active markets. Legacy estimates the option value of puts and calls combined into hedges, including three-way collars and enhanced swaps using an option pricing model which takes into account market volatility, market prices, contract parameters and discount rates based on published LIBOR rates and interest swap rates. Due to the lack of an active market for periods beyond one-month from the balance sheet date for our oil price differential swaps, Legacy has reviewed historical differential prices and known economic influences to estimate a reasonable forward curve of future pricing scenarios based upon these factors. In order to estimate the fair value of our interest rate swaps, Legacy uses a yield curve based on money market rates and interest rate swaps, extrapolates a forecast of future interest rates, estimates each future cash flow, derives discount factors to value the fixed and floating rate cash flows of each swap, and then discounts to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities

are based on readily available money market rates and interest swap market data. The determination of the fair values above incorporates various factors including the impact of our non-performance risk and the credit standing of the counterparties involved in the Partnership's derivative contracts. The risk of nonperformance by the Partnership's counterparties is mitigated by the fact that such current counterparties (or their affiliates) are also current or former bank lenders under

the Partnership's revolving credit facility. In addition, Legacy routinely monitors the creditworthiness of its counterparties. As the factors described above are based on significant assumptions made by management, these assumptions are the most sensitive to change.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Significant Unobservable Inputs (Level 3)		
	December 31,		
	2014	2013	2012
	(In thousands)		
Beginning balance	$20,615	$29,966	$30,054
Total gains (losses)	(6,185)	4,671	18,993
Settlements	677	(6,722)	(19,081)
Transfers	(14,552) (a)	(7,300) (b)	—
Ending balance	$555	$20,615	$29,966
Gains included in earnings relating to derivatives still held as of December 31, 2014, 2013 and 2012	$555	$1,407	$16,065

(a) During 2014, as part of a routine review of accounting policies and practices, Legacy reviewed the assumptions and inputs used to value its derivative instruments and determined the material inputs (such as quoted market prices and oil and natural gas volatility) for its commodity derivatives more accurately correlate to the description of Level 2 instruments. As such, all instruments previously classified as Level 3 (oil and natural gas collars, swaptions and natural gas swaps for those derivatives indexed to the West Texas Waha, ANR-Oklahoma and CIG Indices) with the exception of our Midland-Cushing crude oil differential swaps have been transferred to Level 2 instruments.

(b) During December 2013, Legacy amended three separate contracts with two counterparties to convert contracts from three-way collar contracts to fixed price swap contracts. As fixed price swap contracts are classified as Level 2, the value on the date of the amendment was transferred from a Level 3 classification to Level 2.

During periods of market disruption, including periods of volatile oil and natural gas prices, rapid credit contraction or illiquidity, it may be difficult to value certain of the Partnerships' derivative instruments if trading becomes less frequent and/or market data becomes less observable. There may be certain asset classes that were in active markets with observable data that become illiquid due to changes in the financial environment. In such cases, more derivative instruments may fall to Level 3 and thus require more subjectivity and management judgment. As such, valuations may include inputs and assumptions that are less observable or require greater estimation as well as valuation methods which are more sophisticated or require greater estimation thereby resulting in valuations with less certainty. Further, rapidly changing commodity and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within our consolidated financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on our results of operations or financial condition.

Fair Value on a Non-Recurring Basis

Nonfinancial assets and liabilities measured at fair value on a non-recurring basis include certain nonfinancial assets and liabilities as may be acquired in a business combination, measurements of oil and natural gas property impairments, and the initial recognition of asset retirement obligations, for which fair value is used. These asset retirement obligation ("ARO") estimates are derived from historical costs as well as management’s expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, Legacy has designated these measurements as Level 3.

A reconciliation of the beginning and ending balances of Legacy’s asset retirement obligation is presented in Note 11.

Nonrecurring fair value measurements of proved oil and natural gas properties during the years ended December 31, 2014 and 2013 consist of:

Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(In thousands)		
2014			
Impairment(a)	$—	$—	$254,266
Acquisitions(b)	$—	$—	$536,334
2013			
Impairment(a)	$—	$—	$76,137
Acquisitions(b)	$—	$—	$108,415

(a) Legacy periodically reviews oil and natural gas properties for impairment when facts and circumstances indicate that their carrying value may not be recoverable. During the year ended December 31, 2014, Legacy incurred impairment charges of $413.3 million as oil and natural gas properties with a net cost basis of $667.5 million were written down to their fair value of $254.3 million. During the year ended December 31, 2013, Legacy incurred impairment charges of $78.0 million as oil and natural gas properties with a net cost basis of $154.1 million were written down to their fair value of $76.1 million. In order to determine whether the carrying value of an asset is recoverable, Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management’s expectations of future oil and natural gas prices. These future price scenarios reflect Legacy’s estimation of future price volatility. If the net capitalized cost exceeds the undiscounted future net cash flows, Legacy writes the net cost basis down to the discounted future net cash flows, which is management's estimate of fair value. Significant inputs used to determine the fair value include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices. The inputs used by management for the fair value measurements utilized in this review include significant unobservable inputs, and therefore, the fair value measurements employed are classified as Level 3 for these types of assets.

The remaining $35.4 million of impairment during the year ended December 31, 2014 was $34.95 million of impairment of unproved properties acquired since 2010 that are no longer viable and $0.5 million of impairment of goodwill related to an acquisition completed in 2010. In 2013, Legacy recognized an additional $7.8 million of impairment of unproved properties acquired since 2010 that are no longer viable.

(b) Legacy records the fair value of assets and liabilities acquired in business combinations. During the year ended December 31, 2014, Legacy acquired oil and natural gas properties with a fair value of $536.3 million in the WPX Acquisition and 6 immaterial transactions, both individually and in the aggregate. During the year ended December 31, 2013, Legacy acquired oil and natural gas properties with a fair value of $108.4 million in 16 immaterial transactions, both individually and in the aggregate. Properties acquired are recorded at fair value, which correlates to the discounted future net cash flow. Significant inputs used to determine the fair value include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices. For acquired unproved properties, the market-based weighted average cost of capital rate is subjected to additional project specific risking factors. The inputs used by management for the fair value measurements of these acquired oil and natural gas properties include significant unobservable inputs, and therefore, the fair value measurements employed are classified as Level 3 for these types of assets.

(9) Derivative Financial Instruments

Commodity derivative transactions

Due to the volatility of oil and natural gas prices, Legacy periodically enters into price-risk management transactions (e.g., swaps, enhanced swaps or collars) for a portion of its oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. While the use of these arrangements limits Legacy’s ability to benefit from increases in the prices of oil and natural gas, it also reduces Legacy’s potential exposure to adverse price movements. Legacy’s arrangements, to the extent it enters into any, apply to only a portion of its production, provide only partial price protection against declines in oil and natural gas prices and limit Legacy’s potential gains from future increases in prices. None of these instruments are used for trading or speculative purposes.

These derivative instruments are intended to mitigate a portion of Legacy’s price-risk and may be considered hedges for economic purposes, but Legacy has chosen not to designate them as cash flow hedges for accounting purposes. Therefore, all derivative instruments are recorded on the balance sheet at fair value with changes in fair value being recorded in current period earnings.

By using derivative instruments to mitigate exposures to changes in commodity prices, Legacy exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes Legacy, which creates credit risk. Legacy minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties, who currently are all current or former members of Legacy's lending group.

The following table sets forth a reconciliation of the changes in fair value of Legacy's commodity derivatives for the years ended December 31, 2014, 2013, and 2012.

	December 31,		
	2014	2013	2012
	(In thousands)		
Beginning fair value of commodity derivatives	$17,673	$24,148	$(8,443)
Total gain (loss) crude oil derivatives	101,813	(11,977)	34,257
Total gain (loss) natural gas derivatives	36,279	(1,554)	4,236

Crude oil derivative cash settlements paid	5,431	14,160	10,211
Natural gas derivative cash settlements received	(8,097)	(7,104)	(16,113)
Ending fair value of commodity derivatives	$153,099	$17,673	$24,148

Certain of our commodity derivatives and interest rate derivatives are presented on a net basis on the Consolidated Balance Sheets. The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on our Consolidated Balance Sheets as of the dates indicated below (in thousands):

	December 31, 2014		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
		(In thousands)	
Offsetting Derivative Assets:			
Commodity derivatives	$223,778	$(70,679)	$153,099
Interest rate derivatives	—	—	—
Total derivative assets	$223,778	$(70,679)	$153,099
Offsetting Derivative Liabilities:			
Commodity derivatives	$(70,679)	$70,679	$—
Interest rate derivatives	(2,080)	—	(2,080)
Total derivative liabilities	$(72,759)	$70,679	$(2,080)

	December 31, 2013		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
		(In thousands)	
Offsetting Derivative Assets:			
Commodity derivatives	$46,356	$(21,263)	$25,093
Interest rate derivatives	—	—	—
Total derivative assets	$46,356	$(21,263)	$25,093
Offsetting Derivative Liabilities:			
Commodity derivatives	$(28,683)	$21,263	$(7,420)
Interest rate derivatives	(4,759)	—	(4,759)
Total derivative liabilities	$(33,442)	$21,263	$(12,179)

As of December 31, 2014, Legacy had the following NYMEX WTI crude oil swaps paying floating prices and receiving fixed prices for a portion of its future oil production as indicated below:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2015	1,056,301	$93.93	$88.50 - $100.20
2016	228,600	$87.94	$86.30 - $99.85
2017	182,500	$84.75	$84.75

As of December 31, 2014, Legacy had the following Midland-to-Cushing crude oil differential swaps paying a floating differential and receiving a fixed differential for a portion of its future oil production as indicated below:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
Q1 2015	810,000	$(2.34)	$(2.00) - $(2.55)

As of December 31, 2014, Legacy had the following NYMEX WTI crude oil derivative three-way collar contracts that combine a long and short put with a short call as indicated below:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2015	1,362,800	$65.08	$89.69	$111.84
2016	621,300	$63.37	$88.37	$106.40
2017	72,400	$60.00	$85.00	$104.20

As of December 31, 2014, Legacy had the following NYMEX WTI crude oil enhanced swap contracts that combine a short put, a long put and a fixed-price swap as indicated below:

Calendar Year	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
2016	183,000	$57.00	$82.00	$91.70
2017	182,500	$57.00	$82.00	$90.85
2018	127,750	$57.00	$82.00	$90.50

As of December 31, 2014, Legacy had the following NYMEX WTI crude oil enhanced swap contracts that combine a short put and a fixed-price swap as indicated below:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Swap Price per Bbl
2015	868,000	$76.59	$93.68

As of December 31, 2014, Legacy had the following NYMEX Henry Hub, Waha, ANR-OK and CIG-Rockies natural gas swaps paying floating natural gas prices and receiving fixed prices for a portion of its future natural gas production as indicated below:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2015	18,619,300	$4.39	$3.98 - $5.82
2016	1,419,200	$4.30	$4.12 - $5.30

As of December 31, 2014, Legacy had the following NYMEX Henry Hub natural gas derivative three-way collar contracts that combine a long put, a short put and a short call as indicated below:

Calendar Year	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
2015	8,040,000	$3.66	$4.21	$5.01
2016	5,580,000	$3.75	$4.25	$5.08
2017	5,040,000	$3.75	$4.25	$5.53

As of December 31, 2014, Legacy had the following Henry Hub NYMEX to Northwest Pipeline, NGPL Midcon, California SoCal NGI, San Juan Basin and West Texas Waha natural gas differential swaps paying a floating differential and receiving a fixed differential for a portion of its future natural gas production as indicated below:

	2015	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	12,000,000	$(0.13)
NGPL	480,000	$(0.15)
SoCal	240,000	$0.19
San Juan	480,000	$(0.12)
WAHA	6,000,000	$(0.10)

Interest rate derivative transactions

Due to the volatility of interest rates, Legacy periodically enters into interest rate risk management transactions in the form of interest rate swaps for a portion of its outstanding debt balance. These transactions allow Legacy to reduce exposure to interest rate fluctuations. While the use of these arrangements limits Legacy's ability to benefit from decreases in interest rates, it also reduces Legacy's potential exposure to increases in interest rates. Legacy's arrangements, to the extent it enters into any, apply to only a portion of its outstanding debt balance, provide only partial protection against interest rate increases and limit Legacy's potential savings from future interest rate declines. It is never management's intention to hold or issue derivative instruments for speculative trading purposes. Conditions sometimes arise where actual borrowings are less than notional amounts hedged which has and could result in overhedged amounts.

Legacy does not designate these derivatives as cash flow hedges, even though they reduce its exposure to changes in interest rates. Therefore, the mark-to-market of these instruments is recorded in current earnings and classified as a component of interest expense. The total impact on interest expense from the mark-to-market and settlements was as follows:

	December 31,		
	2014	2013	2012
	(In thousands)		
Beginning fair value of interest rate swaps	$(4,759)	$(9,547)	$(12,053)
Total loss on interest rate swaps	(551)	(1,165)	(4,513)
Cash settlements paid	3,230	5,953	7,019
Ending fair value of interest rate swaps	$(2,080)	$(4,759)	$(9,547)

The table below summarizes the interest rate swap liabilities as of December 31, 2014.

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at December 31, 2014
	(Dollars in thousands)			
$29,000	3.070 %	10/16/2007	10/16/2015	$(629)
$13,000	3.112 %	11/16/2007	11/16/2015	(310)

$12,000	3.131	%	11/28/2007	11/28/2015	(286)
$50,000	2.500	%	10/10/2008	10/10/2015	(855)
Total fair value of interest rate derivatives					$(2,080)

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(10) Sales to Major Customers

Legacy sold oil, NGL and natural gas production representing 10% or more of total revenues for the years ended December 31, 2014, 2013 and 2012 to the customers shown below:

	2014	2013	2012
Enterprise (Teppco) Crude Oil, LP	12%	17%	12%
Plains Marketing, LP	10%	7%	10%

In the exploration, development and production business, production is normally sold to relatively few customers. Substantially all of Legacy's customers are concentrated in the oil and natural gas industry and revenue can be materially affected by current economic conditions, the price of certain commodities such as crude oil and natural gas and the availability of alternate purchasers. Legacy believes that the loss of any of its major purchasers would not have a long-term material adverse effect on its operations.

(11) Asset Retirement Obligation

An asset retirement obligation ("ARO") associated with the retirement of a tangible long-lived asset is recognized as a liability in the period in which it is incurred and becomes determinable. When liabilities for dismantlement and abandonment costs, excluding salvage values, are initially recorded, the carrying amount of the related oil and natural gas properties is increased. The fair value of the additions to the ARO asset and liability is estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors; and (iv) a credit-adjusted risk-free interest rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change. Accretion of the liability is recognized each period using the interest method of allocation, and the capitalized cost is depleted using the units of production method. Should either the estimated life or the estimated abandonment costs of a property change materially upon Legacy's periodic review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using Legacy's credit-adjusted-risk-free rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost. When obligations are relieved by sale of the property or plugging and abandoning the well, the related liability and asset costs are removed from Legacy's balance sheet. Any difference in the cost to plug and the related liability is recorded as a gain or loss on Legacy's income statement in the disposal of assets line item.

The following table reflects the changes in the ARO during the years ended December 31, 2014, 2013 and 2012.

	December 31,		
	2014	2013	2012
	(In thousands)		
Asset retirement obligation — beginning of period	$175,786	$162,183	$120,274
Liabilities incurred with properties acquired	50,487	10,969	38,857
Liabilities incurred with properties drilled	941	494	878
Liabilities settled during the period	(2,918)	(2,441)	(2,412)
Liabilities associated with properties sold	(5,891)	(1,606)	—

Current period accretion	8,120	6,187	4,586
Asset retirement obligation — end of period	$226,525	$175,786	$162,183

Each year the Partnership reviews and, to the extent necessary, revises its asset retirement obligation estimates. During 2012, 2013 and 2014, no revisions of previous estimates were deemed necessary.

(12) Partners' Equity

On April 17, 2014, Legacy issued 2,000,000 of its 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") in a public offering at a price of $25.00 per unit. On May 12, 2014 Legacy issued an additional 300,000 Series A Preferred Units pursuant to the underwriters' option to purchase additional Series A Preferred Units. Legacy received aggregate net proceeds of approximately $55.2 million, after deducting underwriting discounts and offering expenses, from the offering of Series A Preferred Units during the year ended December 31, 2014.

On June 17, 2014, Legacy issued 7,000,000 of its 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units") in a public offering at a price of $25.00 per unit. On July 1, 2014, Legacy issued an additional 200,000 Series B Preferred Units pursuant to the underwriters' option to purchase additional Series B Preferred Units. Legacy received aggregate net proceeds of approximately $174.3 million, after deducting underwriting discounts and offering expenses, from the offering of Series B Preferred Units during the year ended December 31, 2014.

Distributions on the Series A Preferred Units and Series B Preferred Units (collectively, the "Preferred Units") are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of the Partnership's general partner. Distributions on the Series A Preferred Units will be payable from, and including, the date of the original issuance to, but not including April 15, 2024 at an initial rate of 8.00% per annum of the stated liquidation preference. Distributions on the Series B Preferred Units will be payable from, and including, the date of the original issuance to, but not including June 15, 2024 at an initial rate of 8.00% per annum of the stated liquidation preference. Distributions accruing on and after April 15, 2024 for the Series A Preferred Units and June 15, 2024 for the Series B Preferred Units will accrue at an annual rate equal to the sum of (a) three-month LIBOR as calculated on each applicable date of determination and (b) 5.24% for Series A Preferred Units and 5.26% for Series B Preferred Units, based on the $25.00 liquidation preference per preferred unit.

At any time on or after April 15, 2019 or June 15, 2019, Legacy may redeem the Series A Preferred Units or Series B Preferred Units, respectively, in whole or in part at a redemption price of $25.00 per Preferred Unit plus an amount equal to all accumulated and unpaid distributions thereon through and including the date of redemption, whether or not declared. Legacy may also redeem the Preferred Units in the event of a change of control.

The Series A Preferred Units and the Series B Preferred Units trade on the NASDAQ Global Select Market under the symbols "LGCYP" and "LGCYO," respectively.

Incentive Distribution Units

On June 4, 2014, Legacy issued 300,000 Incentive Distribution Units to WPX Energy Rocky Mountain, LLC ("WPX") as part of the WPX Acquisition. The Incentive Distribution Units issued to WPX include 100,000 Incentive Distribution Units that immediately vested along with the ability to vest in up to an additional 200,000 Incentive Distribution Units (the "Unvested IDUs") in connection with any future asset sales or transactions completed with Legacy pursuant to the terms of the IDR Holders Agreement. Incentive Distribution Units that are not issued to WPX or other parties will remain in Legacy's treasury for the benefit of all limited partners until such time as Legacy may make future issuances of Incentive Distribution Units.

The Incentive Distribution Units represent a right to incremental cash distributions from Legacy after certain target levels of distributions are paid to unitholders, which targets are set above the current levels of Legacy's distributions to unitholders. The Unvested IDUs do not participate in cash distributions from Legacy until vested. The Unvested IDUs will automatically be forfeited on each of the first two anniversaries of the closing date of the WPX Acquisition in an amount per forfeiture equal to 66,666 Incentive Distribution Units and on the third anniversary of the closing date of the WPX Acquisition in an amount equal to 66,668 Incentive Distribution Units. Unvested IDUs that have not been forfeited will vest ratably at a rate of 10,000 Incentive Distribution Units

per $35.5 million of additional cash consideration that is paid by Legacy to WPX or to a third party (along with the fair market value of any non-cash consideration) in connection with the consummation of any transaction by which Legacy acquires oil and natural gas properties (or rights therein or other assets related thereto) from WPX or jointly with WPX.

In addition, the vested and outstanding Incentive Distribution Units held by WPX may be converted by Legacy, subject to applicable conversion factors, into units on a one-for-one basis at any time when Legacy has made a distribution in respect of its units for each of the four full fiscal quarters prior to the delivery of its conversion notice, and the amount of the distribution in respect of the units for the full quarter immediately preceding delivery of its conversion notice was equal to at least $0.90 per unit; and the amount of all distributions during each quarter within the four-quarter period immediately preceding delivery of its conversion notice did not exceed the adjusted operating surplus, as defined in Legacy's Partnership Agreement, for such quarter. Further, WPX also has the ability to similarly convert any of its vested Incentive Distribution Units beginning three years after June 4, 2014. WPX may not transfer any of the Incentive Distribution Units it holds to any person that is not a controlled affiliate of WPX.

Income (loss) per unit

The following table sets forth the computation of basic and diluted income (loss) per unit:

	Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Net income (loss)	$(283,645)	$(35,272)	$68,637
Distributions to preferred unitholders	(11,694)	—	—
Net income (loss) attributable to unitholders	(295,339)	(35,272)	68,637
Weighted average number of units outstanding	60,053	57,220	48,991
Effect of dilutive securities:			
Restricted and phantom units	—	—	—
Weighted average units and potential units outstanding	60,053	57,220	48,991
Basic and diluted income (loss) per unit	$(4.92)	$(0.62)	$1.40

As of December 31, 2014, 254,183 restricted units and 323,965 phantom units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect. Additionally, as the conditions for conversion on the Incentive Distribution Units have not been met, they have been excluded from the calculation. As of December 31, 2013, 234,686 restricted units and 189,143 phantom units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect. As of December 31, 2012, 230,477 restricted units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect.

(13) Unit-Based Compensation

Long Term Incentive Plan

On March 15, 2006, a Long-Term Incentive Plan (“LTIP”) for Legacy was created and Legacy adopted the LTIP for its employees, consultants and directors, its affiliates and its general partner. The awards under the long-term incentive plan may include unit grants, restricted units, phantom units, unit options and unit appreciation rights (“UARs”). The LTIP permits the grant of awards that may be made or settled in units up to an aggregate of 2,000,000 units. As of December 31, 2014 grants of awards net of forfeitures and, in the case of phantom units, historical exercises covering

1,254,207 units have been made, comprised of 266,014 unit option awards, 533,850 restricted unit awards, 323,965 phantom unit awards and 130,378 unit awards. The UAR awards granted

under the LTIP may only be settled in cash, and therefore are not included in the aggregate number of units granted under the LTIP. The LTIP is administered by the compensation committee of the board of directors ("Compensation Committee") of Legacy's general partner.

The cost of employee services in exchange for an award of equity instruments is measured based on a grant-date fair value of the award (with limited exceptions), and that cost must generally be recognized over the vesting period of the award. However, if an entity that nominally has the choice of settling awards by issuing stock predominately settles in cash, or if an entity usually settles in cash whenever an employee asks for cash settlement, the entity is settling a substantive liability rather than repurchasing an equity instrument. Due to Legacy's historical practice of settling options, UARs and certain phantom unit awards in cash, Legacy accounts for unit options, UARS and certain phantom unit awards by utilizing the liability method. The liability method requires companies to measure the cost of the employee services in exchange for a cash award based on the fair value of the underlying security at the end of each reporting period. Compensation cost is recognized based on the change in the liability between periods.

Unit Appreciation Rights and Unit Options

A UAR is a notional unit that entitles the holder, upon vesting, to receive cash valued at the difference between the closing price of units on the exercise date and the exercise price, as determined on the date of grant. Because these awards are settled in cash, Legacy is accounting for the UARs by utilizing the liability method.

During the year ended December 31, 2012, Legacy issued (i) 82,400 UARs to employees which vest ratably over a three-year period and (ii) 60,336 UARs to employees which cliff-vest at the end of a three-year period. During the year ended December 31, 2013, Legacy issued (i) 156,650 UARs to employees which vest ratably over a three-year period and (ii) 77,506 UARs to employees which cliff-vest at the end of a three-year period. During the year ended December 31, 2014, Legacy issued (i) 136,100 UARs to employees which vest ratably over a three-year period and (ii) 105,174 UARs to employees which cliff-vest at the end of a three-year period. All of the UARs granted in 2014, 2013 and 2012 expire seven years from the grant date and are exercisable when they vest. There were no unit options granted in 2014, 2013 or 2012.

For the years ended December 31, 2014, 2013 and 2012, Legacy recorded compensation expense/(benefit) of $(1.3) million, $0.9 million and $0.3 million, respectively, due to the changes in the compensation liability related to the above awards based on its use of the Black-Scholes model to estimate the December 31, 2014, 2013 and 2012 fair value of these UARs (see Note 8). As of December 31, 2014, there was a total of $20.7 thousand of unrecognized compensation costs related to the unexercised and non-vested portion of the UARs. At December 31, 2014, this cost was expected to be recognized over a weighted-average period of 2.5 years. Compensation expense is based upon the fair value as of the balance sheet date and is recognized as a percentage of the service period satisfied. Based on historical data, Legacy has assumed a volatility factor of approximately 38% and employed the Black-Scholes model to estimate the December 31, 2014 fair value to be realized as compensation cost based on the percentage of the service period satisfied. Based on historical data, Legacy has assumed an estimated forfeiture rate of 4.7%. The Partnership will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.44 per unit.

A summary of option and UAR activity for the year ended December 31, 2014, 2013 and 2012 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2012	620,031	$ 22.36		
Granted	142,736	$ 28.57		
Exercised	(185,482)	$ 19.68		
Forfeited	(61,066)	$ 24.91		
Outstanding at December 31, 2012	516,219	$ 24.71	4.77	$681,214
Options and UARs exercisable at December 31, 2012	168,569	$ 20.54	2.93	$671,583
Outstanding at January 1, 2013	516,219	$ 24.71		
Granted	234,156	$ 26.53		
Exercised	(96,166)	$ 20.21		
Forfeited	(27,166)	$ 26.74		
Outstanding at December 31, 2013	627,043	$ 25.99	5.16	$1,518,416
Options and UARs exercisable at December 31, 2013	240,288	$ 24.02	3.80	$1,061,542
Outstanding at January 1, 2014	627,043	$ 25.99		
Granted	241,274	$ 28.21		
Exercised	(137,252)	$ 24.35		
Forfeited	(61,836)	$ 27.27		
Outstanding at December 31, 2014	669,229	$ 27.01	5.15	$—
Options and UARs exercisable at December 31, 2014	220,056	$ 25.50	3.51	$—

The following table summarizes the status of the Partnership's non-vested UARs since January 1, 2014:

	Non-Vested Options and UARs	
	Number of Units	Weighted-Average Exercise Price
Non-vested at January 1, 2014	386,755	$27.21
Granted	241,274	28.21
Vested	(118,020)	27.03
Forfeited	(60,836)	27.55
Non-vested at December 31, 2014	449,173	$27.75

Legacy has used a weighted-average risk free interest rate of 1.6% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at December 31, 2014. Expected life represents the period of time that options and UARs are expected to be outstanding and is based on the Partnership's best estimate. The following table represents the weighted average assumptions used for the Black-Scholes option-pricing model:

	Year Ended December 31,		
	2014	2013	2012
Expected life (years)	5.15	5.16	4.77
Annual interest rate	1.6 %	1.4 %	1.1 %
Annual distribution rate per unit	$2.44	$2.34	$2.26
Volatility	38 %	50 %	49 %

Phantom Units

Legacy has also issued phantom units under the LTIP to both executive officers, as described below, and certain other employees. A phantom unit is a notional unit that entitles the holder, upon vesting, to receive, in the case of non-executive employees, cash valued at the closing price of units on the vesting date, or, at the discretion of the Compensation Committee, the same number of Partnership units. Because Legacy's current intent is to settle non-executive phantom unit awards in cash, Legacy is accounting for these phantom units by utilizing the liability method. In the case of executive employees, during 2013 the Compensation Committee revised prior grants of phantom units made to executive officers to eliminate any election for cash payment. As these awards can now only be settled in Partnership units, Legacy is accounting for these phantom units by utilizing the equity method as described in ASC 718.

During February 2012, the Compensation Committee approved the award of 30,828 subjective, or service-based, phantom units and 57,189 objective, or performance-based, phantom units to Legacy's five executive officers. During March 2013, the Compensation Committee approved the award of 46,430 subjective, or service-based, phantom units and 76,723 objective, or performance-based, phantom units to Legacy's executive officers. During March 2014, the Compensation Committee approved the award of 117,197 subjective, or service-based, phantom units and 102,572 objective, or performance-based, phantom units to Legacy's executive officers.

Compensation expense related to the phantom units and associated DERs was $2.3 million, $1.2 million and $0.9 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Restricted Units

During the year ended December 31, 2012, Legacy issued an aggregate of 173,645 restricted units to both non-executive employees and certain executives. The majority of these restricted units awarded vest ratably over a three-year period, beginning on the date of grant. During the year ended December 31, 2013, Legacy issued an aggregate of 85,728 restricted units to non-executive employees. The majority of these restricted units awarded vest ratably over a three-year period. During the year ended December 31, 2014, Legacy issued an aggregate of 127,845 restricted units to non-executive employees. The majority of these restricted units awarded vest ratably over a three-year period beginning at the date of grant. Compensation expense related to restricted units was $2.3 million, $2.3 million and $1.8 million for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014, there was a total of $4.7 million of unrecognized compensation costs related to the non-vested portion of these restricted units. At December 31, 2014, this cost was expected to be recognized over a weighted-average period of 2.2 years.

Pursuant to the provisions of ASC 718, Legacy's issued units as reflected in the accompanying consolidated balance sheet at December 31, 2014, do not include 254,183 units related to unvested restricted unit awards.

Board and Additional Executive Units

On May 9, 2012, Legacy granted and issued 3,509 units to each of its five non-employee directors as part of their annual compensation for serving on the board of directors of Legacy's general partner and 2,500 units to an executive officer. The value of each unit was $28.34 at the time of issuance. On May 14, 2013, Legacy granted and issued 3,715 units to each of its five non-employee directors as part of their annual compensation for serving on the board of directors of Legacy's general partner. The value of each unit was $27.39 at the time of issuance. On May 15, 2014, Legacy granted and issued 3,628 units to each of its five non-employee directors as part of their annual compensation for serving on the board of directors of Legacy's general partner. The value of each unit was $27.50 at the time of issuance. None of these units were subject to vesting. Legacy recognized the expense associated with the unit grants on the date of grant.

(14) Subsidiary Guarantors

On April 2, 2014, we filed a registration statement on Form S-3 with the Securities and Exchange Commission ("SEC") to register the issuance and sale of, among other securities, our debt securities, which may be co-issued by Legacy Reserves Finance Corporation. The registration statement also registered guarantees of debt securities by Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc. The Partnership's 2020 Senior Notes were issued in a private offering on December 4, 2012 and were subsequently registered through a public exchange offer that closed on January 8, 2014. The Partnership's 2021 Senior Notes were issued in two separate private offerings on May 28, 2013 and May 8, 2014. $250 million aggregate principal amount of our 2021 Senior Notes were subsequently registered through a public exchange offer that closed on March 18, 2014. The remaining $300 million of aggregate principal amount of our 2021 Senior Notes were subsequently registered through a public exchange offer that closed on February 10, 2015.The 2020 Senior Notes and the 2021 Senior Notes are guaranteed by our 100% owned subsidiaries Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc., which constitute all of our wholly-owned subsidiaries other than Legacy Reserves Finance Corporation, and certain other future subsidiaries (the "Guarantors", together with any future 100% owned subsidiaries that guarantee the Partnership's 2020 Senior Notes and 2021 Senior Notes, the "Subsidiaries"). The Subsidiaries are 100% owned by the Partnership and the guarantees by the Subsidiaries are full and unconditional, except for customary release provisions described in Note 3 - Long-Term Debt. The Partnership has no assets or operations independent of the Subsidiaries, and there are no significant restrictions upon the ability of the Subsidiaries to distribute funds to the Partnership. The guarantees constitute joint and several obligations of the Guarantors.

(15) Subsequent Events

On January 23, 2015, the board of directors of Legacy's general partner declared a $0.61 per unit cash distribution for the quarter ended December 31, 2014 to all unitholders of record on February 2, 2015. This distribution was paid on February 13, 2015.

On January 23, 2015, Legacy announced that its general partner had declared a monthly cash distribution for both its 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units and its 8% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units of $0.166667 per unit payable on February 17, 2015 to unitholders of record on February 2, 2015.

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On February 19, 2015, Legacy announced that its general partner had declared a monthly cash distribution for both its 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units and its 8% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units of $0.166667 per unit payable on March 16, 2015 to unitholders of record on March 2, 2015.

On February 23, 2015, Legacy entered into the Fourth Amendment to the Current Credit Agreement (the "Fourth Amendment"). Pursuant to the Fourth Amendment, the borrowing base under the Current Credit Agreement was decreased from $950 million to $700 million. As of February 23, 2015, Legacy had approximately $130 million drawn under the Current Credit Agreement, leaving approximately $569.9 million of current availability. Pursuant to the Fourth Amendment, the specific ratios or conditions Legacy is now required to maintain have been amended in their entirety to the following:

- secured debt as of the last day of the most recent quarter to EBITDA (as defined in the Current Credit Agreement) in total over the last four quarters of not more than 2.5 to 1.0;
- as of the last day of the most recent quarter, total EBITDA over the last four quarters to total Interest Expense over the last four quarters to be greater than 2.5 to 1.0; and
- consolidated current assets, as of the last day of the most recent quarter and including the unused amount of the total commitments, to consolidated current liabilities as of the last day of the most recent quarter of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC 815, which includes the current portion of oil, natural gas and interest rate derivatives.

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SUPPLEMENTARY INFORMATION

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

Costs incurred by Legacy in oil and natural gas property acquisition and development are presented below:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Development costs	$134,364	$93,433	$67,552
Exploration costs	—	1,066	1,476
Acquisition costs:			
Proved properties	562,649	114,152	624,065
Unproved properties	24,172	5,232	49,588
Total acquisition, development and exploration costs	$721,185	$213,883	$742,681

Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, and to provide facilities to extract, treat, and gather natural gas. Please see page F-3 for total capitalized costs and associated accumulated depletion.

Net Proved Oil, NGL and Natural Gas Reserves (Unaudited)
The proved oil, NGL and natural gas reserves of Legacy have been estimated by an independent petroleum engineer, LaRoche, as of December 31, 2014, 2013 and 2012. These reserve estimates have been prepared in compliance with the Securities and Exchange Commission rules and accounting standards based on the 12-month unweighted first-day-of-the-month average price for December 31, 2014, 2013 and 2012.

The table below includes the reserves associated with the COG 2012 Acquisition which are reflected in the December 31, 2012 balances. An analysis of the change in estimated quantities of oil and natural gas reserves, all of which are located within the United States, is shown below:

	Oil (MBbls)	NGL (MBbls)(a)	Natural Gas (MMcf)(a)	Total (MBoe)
Total Proved Reserves:				
Balance, December 31, 2011	38,178	4,834	122,604	63,446
Purchases of minerals-in-place	17,626	437	53,881	27,043
Ownership revisions	(217)	—	(165)	(245)
Extensions and discoveries	15	—	56	24
Revisions from drilling and recompletions	268	(15)	468	331
Revisions of previous estimates due to price	(807)	(150)	(8,432)	(2,362)
Revisions of previous estimates due to performance	282	(127)	1,315	374
Production	(3,337)	(348)	(10,417)	(5,421)
Balance, December 31, 2012	52,008	4,631	159,310	83,190
Purchases of minerals-in-place	4,359	20	4,381	5,109
Sales of minerals-in-place	(531)	—	—	(531)
Extensions and discoveries	5	—	34	11
Revisions from drilling and recompletions	814	—	1,954	1,140
Revisions of previous estimates due to price	719	(403)	10,608	2,084
Revisions of previous estimates due to performance	4,131	143	(2,939)	3,784
Production	(4,475)	(316)	(14,328)	(7,179)
Balance, December 31, 2013	57,030	4,075	159,020	87,608
Purchases of minerals-in-place	7,506	8,480	289,523	64,240
Sales of minerals-in-place	(176)	—	(808)	(311)
Revisions from drilling and recompletions	888	33	2,594	1,353
Revisions of previous estimates due to price	(3,110)	371	(969)	(2,901)
Revisions of previous estimates due to performance	(429)	149	(5,449)	(1,188)
Production	(4,784)	(735)	(25,936)	(9,842)
Balance, December 31, 2014	56,925	12,373	417,975	138,959
Proved Developed Reserves:				
December 31, 2011	32,481	4,439	110,909	55,405
December 31, 2012	46,260	4,497	145,538	75,013
December 31, 2013	48,775	3,870	139,789	75,943
December 31, 2014	47,203	12,073	402,802	126,410
Proved Undeveloped Reserves:				
December 31, 2011	5,697	395	11,695	8,041
December 31, 2012	5,748	135	13,772	8,178
December 31, 2013	8,255	205	19,231	11,665
December 31, 2014	9,722	300	15,173	12,551

(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, Legacy's realized natural gas prices in the Permian Basin are substantially higher than NYMEX Henry Hub natural gas prices due to NGL content.

The primary drivers behind the changes to our proved reserves in each of 2012, 2013 and 2014 are described in more detail below.

2012: The increase in proved reserve quantities for the year ended December 31, 2012 was primarily due to our acquisition of producing properties in 20 separate transactions, including the COG 2012 Acquisition.

2013: The increase in proved reserve quantities for the year ended December 31, 2013 was due primarily to our acquisition of producing properties in 16 separate transactions as well as revisions due to performance, comprised mainly of PUD additions. This increase was partially offset by a net decrease in forecasted production across our property set. The net decrease in forecasted production was not in one primary field, but instead, spread across all of our fields.

2014: The increase in proved reserve quantities for the year ended December 31, 2014 was due primarily to our acquisition of producing properties in 7 separate transactions, including the WPX Acquisition. This increase was partially offset by a net decrease in reserves due to the decline in average NYMEX-WTI oil prices during 2014.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves (Unaudited)

Summarized in the following table is information for Legacy inclusive of the COG 2012 Acquisition in 2012 with respect to the standardized measure of discounted future net cash flows relating to proved reserves. Future cash inflows are computed by applying the 12-month unweighted first-day-of-the-month average price for the years ended December 31, 2014, 2013 and 2012. Future production, development, site restoration, and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future net cash flows have not been adjusted for commodity derivative contracts outstanding at the end of each year. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on their share of Legacy's taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary, as discussed in Note 1(f), 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.

	December 31,		
	2014	2013	2012
	(In thousands)		
Future production revenues	$7,243,050	$6,205,770	$5,528,850
Future costs:			
Production	(3,457,818)	(2,738,136)	(2,503,052)
Development	(473,954)	(303,319)	(229,014)
Future net cash flows before income taxes	3,311,278	3,164,315	2,796,784
10% annual discount for estimated timing of cash flows	(1,556,664)	(1,607,335)	(1,370,932)
Standardized measure of discounted net cash flows	$1,754,614	$1,556,980	$1,425,852

The standardized measure is based on the following oil and natural gas prices realized over the life of the properties at the wellhead as of the following dates:

	December 31,		
	2014	2013	2012

Oil (per Bbl) (a)	$91.48	$93.42	$91.17
Natural Gas (per MMBtu) (b)	$4.35	$3.67	$2.76

(a) The quoted oil price for all fiscal years is the 12-month unweighted average first-day-of-the-month West Texas Intermediate price, as posted by Plains Marketing, L.P., for each month of 2014, 2013 and 2012.

(b) The quoted gas price for all fiscal years is the 12-month unweighted average first-day-of-the-month Henry Hub price, as posted by Platts Gas Daily, for each month of 2014, 2013 and 2012.

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Increase (decrease):			
Sales, net of production costs	$(301,964)	$(301,301)	$(212,730)
Net change in sales prices, net of production costs	(213,617)	78,402	(153,161)
Changes in estimated future development costs	64,273	23,062	16,198
Extensions and discoveries, net of future production and development costs	—	183	639
Revisions of previous estimates due to infill drilling, recompletions and stimulations	39,228	34,267	8,512
Revisions of previous quantity estimates due to performance	(39,227)	45,830	3,242
Previously estimated development costs incurred	51,085	29,527	33,858
Purchases of minerals-in-place	472,057	102,239	496,099
Sales of minerals-in-place	(2,932)	(4,146)	—
Ownership interest changes	—	—	(6,853)
Other	(26,758)	(12,432)	(13,077)
Accretion of discount	155,489	135,497	112,724
Net increase	197,634	131,128	285,451
Standardized measure of discounted future net cash flows:			
Beginning of year	1,556,980	1,425,852	1,140,401
End of year	$1,754,614	$1,556,980	$1,425,852

The data presented should not be viewed as representing the expected cash flow from or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts.

SUPPLEMENTARY INFORMATION — (Continued)

Selected Quarterly Financial Data (Unaudited)

For the three-month periods ended:

	March 31	June 30	September 30	December 31
2014	(In thousands, except per unit data)			
Revenues:				
Oil sales	$102,055	$108,731	$105,640	$80,348
Natural gas liquids sales	3,965	5,103	10,413	8,002
Natural gas sales	19,883	23,280	33,623	31,256
Total revenues	125,903	137,114	149,676	119,606
Expenses:				
Oil and natural gas production	42,534	45,809	55,491	54,967
Production and other taxes	7,955	8,595	7,742	7,242
General and administrative	7,647	14,809	8,325	8,199
Depletion, depreciation, amortization and accretion	33,697	38,537	48,016	53,436
Impairment of long-lived assets	1,412	2,387	4,785	440,130
(Gain) loss on disposal of assets	2,301	(3,853)	(1,683)	756
Total expenses	95,546	106,284	122,676	564,730
Operating income (loss)	30,357	30,830	27,000	(445,124)
Interest income	223	216	223	211
Interest expense	(13,939)	(16,225)	(19,083)	(17,971)
Equity in income of partnership	(8)	191	126	119
Net gains (losses) on commodity derivatives	(15,886)	(31,433)	55,994	129,417
Other	93	211	(166)	120
Income (loss) before income taxes	840	(16,210)	64,094	(333,228)
Income taxes	(314)	(278)	(278)	1,729
Net income (loss)	$526	$(16,488)	$63,816	$(331,499)
Distributions to preferred unitholders	—	(2,194)	(4,750)	(4,750)
Net income (loss) attributable to unitholders	$526	$(18,682)	$59,066	$(336,249)
Net income (loss) per unit — basic	$0.01	$(0.33)	$1.03	$(4.94)
Net income (loss) per unit — diluted	$0.01	$(0.33)	$1.02	$(4.94)
Production volumes:				
Oil (MBbl)	1,135	1,175	1,221	1,253
Natural gas liquids (Mgal)	3,362	5,519	10,697	11,283
Natural gas (MMcf)	3,226	4,877	8,867	8,966
Total (MBoe)	1,753	2,119	2,954	3,016

For the three-month periods ended:

	March 31	June 30	September 30	December 31
2013	(In thousands, except per unit data)			
Revenues:				
Oil sales	$90,357	$97,852	$116,396	$100,931
Natural gas liquids sales	3,342	3,161	3,686	3,906
Natural gas sales	15,180	17,373	16,101	17,204
Total revenues	108,879	118,386	136,183	122,041
Expenses:				
Oil and natural gas production	35,351	37,184	39,701	42,443
Production and other taxes	6,927	6,771	8,385	7,425
General and administrative	6,281	7,064	7,933	7,629
Depletion, depreciation, amortization and accretion	41,652	39,113	37,717	39,933
Impairment of long-lived assets	1,743	20,774	835	62,405
(Gain) loss on disposal of assets	(219)	(46)	758	86
Total expenses	91,735	110,860	95,329	159,921
Operating income	17,144	7,526	40,854	(37,880)
Interest income	8	334	227	207
Interest expense	(10,692)	(11,206)	(14,206)	(13,985)
Equity in income of partnership	44	140	172	203
Net gains (losses) on commodity derivatives	(13,005)	25,330	(30,424)	4,568
Other	7	(2)	(16)	29
Income (loss) before income taxes	$(6,494)	$22,122	$(3,393)	$(46,858)
Income taxes	(211)	(368)	(29)	(41)
Net income (loss)	$(6,705)	$21,754	$(3,422)	$(46,899)
Net income (loss) per unit — basic and diluted	$(0.12)	$0.38	$(0.06)	$(0.82)
Production volumes:				
Oil (MBbl)	1,114	1,089	1,141	1,131
Natural gas liquids (Mgal)	2,893	3,320	3,527	3,532
Natural gas (MMcf)	3,546	3,649	3,714	3,419
Total (MBoe)	1,774	1,776	1,844	1,785