LEGACY RESERVES LP
Form 10-Q
May 08, 2015

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

FORM 10-Q

S QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2015

or

£ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-33249

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

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

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

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.

x Yes o No

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).

x Yes £ No

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.

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

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

69,208,533 units representing limited partner interests in the registrant were outstanding as of May 7, 2015.

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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, NGL 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.

NGL or natural gas liquids. 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.

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

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 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%. Because we are a limited partnership that allocates our taxable income to our unitholders, no provisions for federal or state income taxes have been provided for in the calculation of standardized measure. Standardized measure does not give effect to derivative transactions.

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

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

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

Part I – FINANCIAL INFORMATION

Item 1. Financial Statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)
ASSETS

	March 31, 2015	December 31, 2014
	(In thousands)	
Current assets:		
Cash	$3,451	$725
Accounts receivable, net:		
Oil and natural gas	38,658	49,390
Joint interest owners	22,108	16,235
Other	259	237
Fair value of derivatives (Notes 6 and 7)	104,541	120,305
Prepaid expenses and other current assets	4,403	5,362
Total current assets	173,420	192,254
Oil and natural gas properties using the successful efforts method, at cost:		
Proved properties	2,972,336	2,946,820
Unproved properties	48,159	47,613
Accumulated depletion, depreciation, amortization and impairment	(1,601,883)	(1,354,459)
	1,418,612	1,639,974
Other property and equipment, net of accumulated depreciation and amortization of $7,791 and $7,446, respectively	3,560	3,767
Operating rights, net of amortization of $4,620 and $4,509, respectively	2,397	2,508
Fair value of derivatives (Notes 6 and 7)	28,701	32,794
Other assets, net of amortization of $13,243 and $12,551, respectively	25,647	24,255
Investments in equity method investees	3,053	3,054
Total assets	$1,655,390	$1,898,606

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)
LIABILITIES AND PARTNERS' EQUITY

	March 31, 2015	December 31, 2014
	(In thousands)	
Current liabilities:		
Accounts payable	$3,069	$2,787
Accrued oil and natural gas liabilities (Note 1)	55,352	78,615
Fair value of derivatives (Notes 6 and 7)	1,540	2,080
Asset retirement obligation (Note 8)	3,028	3,028
Other (Notes 2 and 10)	24,204	11,066
Total current liabilities	87,193	97,576
Long-term debt (Note 2)	967,440	938,876
Asset retirement obligation (Note 8)	237,218	223,497
Other long-term liabilities	1,328	1,452
Total liabilities	1,293,179	1,261,401
Commitments and contingencies (Note 5)		
Partners' equity (Note 9):		
Series A Preferred equity - 2,300,000 units issued and outstanding at March 31, 2015 and December 31, 2014	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at March 31, 2015 and December 31, 2014	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at March 31, 2015 and December 31, 2014	30,814	30,814
Limited partners' equity - 68,930,150 and 68,910,784 units issued and outstanding at March 31, 2015 and December 31, 2014, respectively	101,952	376,885
General partner's equity (approximately 0.03%)	(8)	53
Total partners' equity	362,211	637,205
Total liabilities and partners' equity	$1,655,390	$1,898,606

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended March 31, 2015	2014
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$50,296	$102,055
Natural gas liquids (NGL) sales	4,192	3,965
Natural gas sales	27,051	19,883
Total revenues	81,539	125,903
Expenses:		
Oil and natural gas production	49,220	42,534
Production and other taxes	4,218	7,955
General and administrative	8,869	7,647
Depletion, depreciation, amortization and accretion	41,068	33,697
Impairment of long-lived assets	209,402	1,412
Loss on disposal of assets	1,941	2,301
Total expenses	314,718	95,546
Operating income (loss)	(233,179)	30,357
Other income (expense):		
Interest income	206	223
Interest expense (Notes 2, 6 and 7)	(17,792)	(13,939)
Equity in income of equity method investees	79	(8)
Net gains (losses) on commodity derivatives (Notes 6 and 7)	20,480	(15,886)
Other	605	93
Income (loss) before income taxes	(229,601)	840
Income tax (expense) benefit	747	(314)
Net income (loss)	$(228,854)	$526
Distributions to Preferred unitholders	(4,750)	—
Net income (loss) attributable to unitholders	$(233,604)	$526
Income (loss) per unit - basic and diluted (Note 9)	$(3.39)	$0.01
Weighted average number of units used in computing net income (loss) per unit -		
Basic	68,921	57,309
Diluted	68,921	57,367

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
FOR THE THREE MONTHS ENDED MARCH 31, 2015
(UNAUDITED)

	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, 2014	2,300	$55,192	7,200	$174,261	100	$30,814	68,911	$376,885	$53	$637,205
Unit-based compensation	—	—	—	—	—	—	—	976	—	976
Vesting of restricted and phantom units	—	—	—	—	—	—	19	—	—	—
Offering costs associated with the issuance of units	—	—	—	—	—	—	—	(30)	—	(30)
Distributions to preferred unitholders	—	—	—	—	—	—	—	(4,750)	—	(4,750)
Distributions to unitholders, $0.61 per unit	—	—	—	—	—	—	—	(42,336)	—	(42,336)
Net loss	—	—	—	—	—	—	—	(228,793)	(61)	(228,854)
Balance, March 31, 2015	2,300	$55,192	7,200	$174,261	100	$30,814	68,930	$101,952	$(8)	$362,211

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Three Months Ended March 31, 2015	2014
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$(228,854)	$526
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	41,068	33,697
Amortization of debt discount and issuance costs	1,256	1,012
Impairment of long-lived assets	209,402	1,412
(Gain) loss on derivatives	(21,019)	15,175
Equity in income of equity method investees	(79)	8
Distribution from equity method investee	80	204
Unit-based compensation	981	1
Loss on disposal of assets	1,941	2,301
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, oil and natural gas	10,732	(12,185)
(Increase) decrease in accounts receivable, joint interest owners	(5,873)	575
(Increase) decrease in accounts receivable, other	(22)	97
(Increase) decrease in other assets	318	(41)
Increase in accounts payable	282	2,131
Increase (decrease) in accrued oil and natural gas liabilities	(23,262)	10,711
Increase in other liabilities	10,873	4,545
Total adjustments	226,678	59,643
Net cash provided by (used in) operating activities	(2,176)	60,169
Cash flows from investing activities:		
Investment in oil and natural gas properties	(15,057)	(22,383)
Increase in deposits on pending acquisitions	—	(11,200)
Proceeds from sale of assets	320	58
Investment in other equipment	(138)	(232)
Net cash settlements on commodity derivatives	40,337	(3,610)
Net cash provided by (used in) investing activities	25,462	(37,367)
Cash flows from financing activities:		
Proceeds from long-term debt	80,000	126,000
Payments of long-term debt	(52,000)	(114,000)
Payments of debt issuance costs	(1,444)	(58)
Offering costs associated with the issuance of units	(30)	(105)
Distributions to unitholders	(47,086)	(34,251)
Net cash used in financing activities	(20,560)	(22,414)
Net increase in cash and cash equivalents	2,726	388
Cash and cash equivalents, beginning of period	725	2,584
Cash and cash equivalents, end of period	$3,451	$2,972
Non-cash investing and financing activities:		
Asset retirement obligations associated with property acquisitions	$11,725	$—

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

(1) Summary of Significant Accounting Policies

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

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

The accompanying condensed consolidated financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred. These condensed consolidated financial statements as of March 31, 2015 and for the three months ended March 31, 2015 and 2014 are unaudited. In the opinion of management, such financial statements include the adjustments and accruals, all of which are of a normal recurring nature, which are necessary for a fair presentation of the results for the interim periods. These interim results are not necessarily indicative of results for a full year.

Certain information and footnote disclosures normally included in the financial statements prepared in accordance with generally accepted accounting principles in the United States (“GAAP”) have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). These condensed consolidated financial statements should be read in connection with the consolidated financial statements and notes thereto included in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2014.

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 owns an approximate 0.03% general partner interest in LRLP.

Significant information regarding rights of unitholders includes the following:

•Right to receive, within 45 days after the end of each quarter, distributions of available cash, if distributions are declared.

•No limited partner shall have any management power over LRLP’s 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 LRGPLLC and its affiliates, provided that a unit majority has elected a successor general partner.

•Right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year.

In the event of 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 LRGPLLC 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.

(b) Accrued Oil and Natural Gas Liabilities

Below are the components of accrued oil and natural gas liabilities as of March 31, 2015 and December 31, 2014:

	March 31, 2015	December 31, 2014
	(In thousands)	
Revenue payable	$12,972	$19,267
Accrued lease operating expense	19,673	21,177
Accrued capital expenditures	7,984	20,773
Accrued ad valorem tax	8,721	9,382
Other	6,002	8,016
	$55,352	$78,615

(c) Recent Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs" ("ASU 2015-03") which changes the presentation of debt issuance costs in financial statements to present such costs as a direct deduction from the related debt liability rather than as an asset. ASU 2015-03 will become effective for public companies during interim and annual reporting periods beginning after December 15, 2015. Early adoption is permitted. We do not expect the adoption of ASU 2015-03 will have a material impact on our consolidated financial statements.

(2) Long-Term Debt

Long-term debt consists of the following as of March 31, 2015 and December 31, 2014:

	March 31, 2015	December 31, 2014
	(In thousands)	
Credit Facility due 2019	$137,000	$109,000
8% Senior Notes due 2020	300,000	300,000
6.625% Senior Notes due 2021	550,000	550,000
	987,000	959,000
Unamortized discount on Senior Notes	(19,560)	(20,124)
Total Long-Term Debt	$967,440	$938,876

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 (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 its 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 and was re-affirmed on March 27, 2015. The borrowing base is subject to semi-annual redeterminations on April 1 and October 1 of each year with the next redetermination scheduled for October 1, 2015. 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 1.50% to 2.50%, 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 0.50% to 1.50% 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 follows: (i) secured debt as of the last day of the most recent quarter to EBITDA in total over the last four quarters of not more than 2.5 to 1.0, (ii) 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 (iii) 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 FASB Accounting Standards Codification 815, which includes the current portion of oil, natural gas and interest rate derivatives.

As of March 31, 2015, Legacy had approximately $137 million drawn under the Current Credit Agreement at a weighted-average interest rate of 1.79%, leaving approximately $562.9 million of availability under the Current Credit Agreement. For the three-month period ended March 31, 2015, Legacy paid in cash $1.2 million of interest expense on the Current Credit Agreement.

At March 31, 2015, Legacy was in compliance with all covenants of 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 and thereafter	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's 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., which constitute all of Legacy's wholly-owned subsidiaries other than Legacy Reserves Finance Corporation. 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 11 - 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 financial and other 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 99.0% 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 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 financial and other covenants of the 2021 Senior Notes.

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

(3) Acquisitions

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 fully 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.

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 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 and do not include any adjustments for acquisition related expenses.

	Three Months Ended March 31, 2014
Revenues	$148,787
Net income (loss) attributable to unitholders	$4,116
Income (loss) per unit — basic and diluted	$0.07
Units used in computing income (loss) per unit:	
Basic	57,309
Diluted	57,367

(4) Related Party Transactions

Cary D. Brown, Chairman of the board of LRGPLLC, Kyle A. McGraw, Director and Executive Vice President and Chief Development Officer of LRGPLLC and Dale Brown, Director of LRGPLLC, 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 $65,770, without respect to property taxes and insurance. The lease expires in September 2020.

(5) 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 CO_2 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 March 31, 2015, we estimate the value of our total future obligation to be approximately $56.6 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.

(6) 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.

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 March 31, 2015:

	Fair Value Measurements at March 31, 2015 Using			
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Total Carrying Value as of
Description	(Level 1)	(Level 2)	(Level 3)	March 31, 2015
	(In thousands)			
LTIP liability (a)	$—	$(16)	$—	$(16)
Oil and natural gas derivatives	—	135,727	(2,485)	133,242
Interest rate swaps	—	(1,540)	—	(1,540)
Total	$—	$134,171	$(2,485)	$131,686

(a) See Note 10 for further discussion on unit-based compensation expenses and the related Long-Term Incentive Plan ("LTIP") liability for certain grants accounted for under the liability method.

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 rate swaps. 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 most of our 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)	
	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Beginning balance	$555	$20,615
Total losses	(3,357)	(6,740)
Settlements, net	317	677
Ending balance	$(2,485)	$14,552
Losses included in earnings relating to derivatives still held as of March 31, 2015 and 2014	$(2,485)	$(5,622)

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 Partnership's derivative instruments if trading becomes less frequent and/or
market data becomes less observable. There may be certain asset classes that were previously 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 and thereby measured at fair value; measurements of oil and natural gas property impairments; and the initial recognition of asset retirement obligations ("ARO") for which fair value is used. These 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 liabilities as Level 3. A reconciliation of the beginning and ending balances of Legacy’s asset retirement obligation is presented in Note 8.

Assets measured at fair value during the three-month period ended March 31, 2015 include:

	Fair Value Measurements at March 31, 2015 Using		
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
Description	(Level 1)	(Level 2)	(Level 3)
	(In thousands)		
Assets:			

Impairment (a)	$—	$—	$198,095
Acquisitions (b)	$—	$—	$1,691

(a) Legacy reviews oil and natural gas properties 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. During the three-month period ended March 31, 2015, Legacy incurred impairment charges of $209.4 million as oil and natural gas properties with a net cost basis of $407.5

million were written down to their fair value of $198.1 million. In order to determine fair value, 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.

(b) Assets and liabilities acquired in a business combination are recorded at fair value. During the three-month period ended March 31, 2015, Legacy acquired oil and natural gas properties, inclusive of unproved acreage acquisitions, with a fair value of $1.7 million in multiple individually immaterial transactions. 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.

The carrying amount of the revolving long-term debt of $137 million as of March 31, 2015 approximates fair value because Legacy's current borrowing rate does not materially differ from market rates for similar bank borrowings. Legacy has classified the revolving long-term debt as a Level 2 item within the fair value hierarchy. As of March 31, 2015, the fair values of the 2020 Senior Notes and the 2021 Senior Notes were $258.3 million and $434.5 million, respectively. As these valuations are based on unadjusted quoted prices in an active market, the fair values are classified as Level 1 items within the fair value hierarchy.

(7) 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 and required no upfront or deferred cash premium paid or payable to our counterparty.

All of these price risk management transactions are considered derivative instruments. These derivative instruments are intended to reduce 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, most of whom are 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 three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Beginning fair value of commodity derivatives	$153,099	$17,673
Total gain (loss) - oil derivatives	13,594	(12,260)
Total gain (loss) - natural gas derivatives	6,886	(3,626)
Crude oil derivative cash settlements paid (received)	(32,200)	2,556
Natural gas derivative cash settlements paid (received)	(8,137)	1,054
Ending fair value of commodity derivatives	$133,242	$5,397

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):

	March 31, 2015		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:		(In thousands)	
Commodity derivatives	$203,594	$(70,352)	$133,242
Total derivative assets	$203,594	$(70,352)	$133,242
Offsetting Derivative Liabilities:			
Commodity derivatives	$(70,352)	$70,352	$—
Interest rate derivatives	(1,540)	—	(1,540)
Total derivative liabilities	$(71,892)	$70,352	$(1,540)

	December 31, 2014		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:		(In thousands)	
Commodity derivatives	$223,778	$(70,679)	$153,099
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)

As of March 31, 2015, Legacy had the following NYMEX West Texas Intermediate ("WTI") crude oil swaps paying floating prices and receiving fixed prices for a portion of its future oil production as indicated below:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
April-December 2015	914,735	$79.14	$52.00 - $100.20
2016	228,600	$87.94	$86.30 - $99.85
2017	182,500	$84.75	$84.75

As of March 31, 2015, 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
April-December 2015	2,475,000	$(1.77)	$(1.65) - $(1.90)

As of March 31, 2015, Legacy had the following NYMEX WTI crude oil derivative three-way collar contracts that combine a long put, a short put and a short call as indicated below:

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
April-December 2015	997,400	$64.87	$89.60	$111.39
2016	621,300	$63.37	$88.37	$106.40
2017	72,400	$60.00	$85.00	$104.20

As of March 31, 2015, 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:

Time Period	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 March 31, 2015, Legacy had the following NYMEX WTI crude oil enhanced swap contracts that combine a short put and a fixed-price swap as indicated below:

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Swap Price per Bbl
April-December 2015	688,000	$77.01	$93.79

As of March 31, 2015, Legacy had the following NYMEX Henry Hub, West Texas 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:

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
April-December 2015	13,963,300	$4.39	$3.98 - $5.82
2016	1,419,200	$4.30	$4.12 - $5.30

As of March 31, 2015, 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:

Time Period	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
April-December 2015	6,030,000	$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 March 31, 2015, 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:

	April-December 2015	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	9,000,000	$(0.13)
NGPL	360,000	$(0.15)
SoCal	180,000	$0.19
San Juan	360,000	$(0.12)
WAHA	4,500,000	$(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 accounts for these interest rate swaps at fair market value and included in the consolidated balance sheet as assets or liabilities.

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 as a component of interest expense. The total impact on interest expense from the mark-to-market and settlements was as follows:

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Beginning fair value of interest rate swaps	$(2,080)	$(4,759)
Total loss on interest rate swaps	(148)	(174)
Cash settlements paid	688	886
Ending fair value of interest rate swaps	$(1,540)	$(4,047)

The table below summarizes the interest rate swap position as of March 31, 2015:

Notional Amount	Fixed Rate		Effective Date	Maturity Date	Estimated Fair Market Value at March 31, 2015	
(Dollars in thousands)						
$29,000	3.070	%	10/16/2007	10/16/2015	$(459	)
$13,000	3.112	%	11/16/2007	11/16/2015	(235	)
$12,000	3.131	%	11/28/2007	11/28/2015	(215	)
$50,000	2.500	%	10/10/2008	10/10/2015	(631	)
Total fair market value of interest rate derivatives					$(1,540	)

(8) Asset Retirement Obligation

AROs associated with the retirement of a tangible long-lived asset are recognized as a liability in the period in which it is incurred and becomes determinable. Under this method, 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 ARO asset and liability is measured using expected future cash outflows discounted at Legacy’s credit-adjusted risk-free interest rate. Accretion of the liability is recognized each period using the interest method of allocation, and the capitalized cost is depleted over the useful life of the related asset.

The following table reflects the changes in the ARO during the three months ended March 31, 2015 and year ended December 31, 2014:

	March 31, 2015		December 31, 2014	
	(In thousands)			
Asset retirement obligation - beginning of period	$226,525		$175,786	
Liabilities incurred with properties acquired	11,725		50,487	
Liabilities incurred with properties drilled	—		941	
Liabilities settled during the period	(502	)	(2,918	)
Liabilities associated with properties sold	(19	)	(5,891	)
Current period accretion	2,517		8,120	
Asset retirement obligation - end of period	$240,246		$226,525	

(9) Partners' Equity

Preferred Units

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.

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, the underwriters exercised their over-allotment option to purchase an additional 200,000 Series B Preferred Units.

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 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.

The Series A Preferred Units and the Series B Preferred Units trade on NASDAQ 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. 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 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:

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Net income (loss)	$(228,854)	$526

Distributions to preferred unitholders	(4,750)	—
Net income (loss) available to unitholders	(233,604)	526
Weighted average number of units outstanding	68,921	57,309
Effect of dilutive securities:		
Restricted and phantom units	—	58
Weighted average units and potential units outstanding	68,921	57,367
Basic and diluted income (loss) per unit	$(3.39)	$0.01

For the three months ended March 31, 2015, 278,383 restricted units and 862,064 phantom units were excluded from the calculation of diluted income per unit due to their anti-dilutive effect. For the three months ended March 31, 2014, 201,643 restricted units and 289,977 phantom units were excluded from the calculation of diluted income per unit due to their anti-dilutive effect.

(10) Unit-Based Compensation

Long-Term Incentive Plan

On March 15, 2006, the LTIP for Legacy was implemented for its employees, consultants and directors, its affiliates and its general partner. The awards under the LTIP 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 March 31, 2015, grants of awards net of forfeitures and, in the case of phantom units, historical exercises covering 1,820,306 units had been made, comprised of 266,014 unit option awards, 561,850 restricted unit awards, 862,064 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 (the "Compensation Committee") of the board of directors of LRGPLLC.

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 and UARs in cash, Legacy accounts for unit options and UARs 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, 2014, Legacy issued 136,100 UARs to employees which vest ratably over a three-year period and 105,174 UARs to employees which vest at the end of a three-year period. During the three-month period ended March 31, 2015, Legacy issued 13,500 UARs to employees which vest ratably over a three-year period. All UARs granted in 2014 and 2015 expire seven years from the grant date and are exercisable when they vest.

For the three-month periods ended March 31, 2015 and 2014, Legacy recorded $5,181 and $(162,916), respectively, of compensation expense (benefit) due to the change in liability from December 31, 2014 and 2013, respectively, based on its use of the Black-Scholes model to estimate the March 31, 2015 and 2014 fair value of these UARs (see Note 6). As of March 31, 2015, there was a total of approximately $12,321 of unrecognized compensation costs related to the unexercised and non-vested portion of these UARs. At March 31, 2015, this cost was expected to be recognized over a weighted-average period of approximately 2.43 years. Compensation expense is based upon the fair value as of March 31, 2015 and is recognized as a percentage of the service period satisfied. Based on historical data, Legacy has assumed a volatility factor of approximately 42% and employed the Black-Scholes model to estimate the

March 31, 2015 fair value to be realized as compensation cost based on the percentage of service period satisfied. Based on historical data, Legacy has assumed an estimated forfeiture rate of 4.7%. Legacy will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.44 per unit. Due to the timing of the valuation, this distribution rate does not reflect the reduced quarterly distribution rate as the reduction was determined subsequent to the period end.

A summary of UAR and unit option activity for the three months ended March 31, 2015 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2015	671,229	$ 26.97		
Granted	13,500	11.16		
Forfeited	(2,800)	29.62		
Outstanding at March 31, 2015	681,929	$ 26.65	4.9	$900
Options and UARs exercisable at March 31, 2015	244,219	$ 25.58	3.4	$—

The following table summarizes the status of Legacy's non-vested UARs since January 1, 2015:

	Non-Vested UARs	
	Number of Units	Weighted-Average Exercise Price
Non-vested at January 1, 2015	451,173	$ 27.69
Granted	13,500	11.16
Vested	(24,163)	26.36
Forfeited	(2,800)	29.62
Non-vested at March 31, 2015	437,710	$ 27.24

Legacy has used a weighted-average risk-free interest rate of 1.3% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at March 31, 2015 whose terms are consistent with the expected life of the UARs and unit options. Expected life represents the period of time that UARs and unit options are expected to be outstanding and is based on Legacy's best estimate. The following table represents the weighted-average assumptions used for the Black-Scholes option-pricing model.

	Three Months Ended March 31, 2015	
Expected life (years)	4.94	
Risk free interest rate	1.3	%
Annual distribution rate per unit	$2.44	
Volatility	42	%

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 one Partnership unit for each phantom unit. Legacy is accounting for these phantom units by utilizing the equity method.

On September 21, 2009, the board of directors of LRGPLLC, upon the recommendation of the Compensation Committee, implemented an equity-based incentive compensation policy applicable to the executive officers of Legacy. In addition to cash bonus awards, under the compensation plan, the executives are eligible for both subjective and objective grants of phantom units. The subjective, or service-based, grants may be awarded up to a maximum percentage of annual salary as determined by the Compensation Committee. Once granted, these phantom units vest ratably over a three-year period. The objective, or performance-based, grants may be awarded up to a maximum percentage of annual salary as determined by the Compensation Committee. However, the amount to vest each year for the three-year vesting period will be determined on each vesting date based on a three-step process, with the first two steps each comprising 50% of the total vesting amount while the third step is the sum of the first two steps. The first step in the process will be a function of Total Unitholder Return (“TUR”)

for the Partnership and the percentage rank of the Legacy TUR among a peer group of upstream master limited partnerships, as determined by the Compensation Committee at the beginning of each year. In the second step, the Legacy TUR will be compared to the TUR of a group of master limited partnerships included in the Alerian MLP Index. The third step is the addition of the above two steps to determine the total performance-based awards to vest.
On March 7, 2013, the board of directors of LRGPLLC, upon the recommendation of the Compensation Committee, approved a revised compensation policy (the “Revised Policy”). This Revised Policy applies to incentive awards granted after the fiscal year ended 2013. While the Revised Policy measures TUR against both the peer group and Alerian MLP Index, the measurement periods were increased to a three-year cumulative measurement period with a corresponding increase in vesting from a ratable three-year vesting to three-year cliff vesting. Performance based phantom units subject to vesting which do not vest in a given year will be forfeited. With respect to both the subjective and objective units awarded under both compensation policies, distribution equivalent rights ("DERs") will accumulate and accrue based on the total number of actual amounts vested and will be payable at the date of vesting. However, due to the aforementioned revision for executive employees, accrued DERs paid at the date of vesting will be treated as distributions in the period paid rather than being recognized as compensation expense over the life of the award.

On March 4, 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. On February 24, 2015, the Compensation Committee approved the award of 341,251 subjective, or service-based, phantom units and 259,998 objective, or performance based, phantom units to Legacy’s executive officers.

Compensation expense related to the phantom units and associated DERs was $0.4 million and $0.3 million for the three months ended March 31, 2015 and 2014, respectively.

Restricted Units

During the year ended December 31, 2014, Legacy issued an aggregate of 127,845 restricted units to non-executive employees. These restricted units awarded typically vest ratably over a three-year period all beginning on or around the date of grant. During the three-month period ended March 31, 2015, Legacy issued an aggregate of 28,000 restricted units to non-executive employees. These restricted units awarded vest ratably over a three-year period. Compensation expense related to restricted units was $0.6 million and $0.5 million for the three months ended March 31, 2015 and 2014, respectively. As of March 31, 2015, there was a total of $4.3 million of unrecognized compensation expense related to the unvested portion of these restricted units. At March 31, 2015, this cost was expected to be recognized over a weighted-average period of 2.1 years. Pursuant to the provisions of ASC 718, Legacy’s issued units, as reflected in the accompanying consolidated balance sheet at March 31, 2015, do not include 278,383 units related to unvested restricted unit awards.

Board Units

On May 15, 2014, Legacy granted and issued 3,628 units to each of its five non-employee directors. The value of each unit was $27.50 at the time of issuance.

(11) 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 2 - 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.

(12) Subsequent Events

On April 16, 2015, Legacy's board of directors approved a distribution of $0.35 per unit payable on May 15, 2015 to unitholders of record on May 1, 2015.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

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 Legacy's Annual Report on Form 10-K for the year ended December 31, 2014 in Item 1A under "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 rely on them unduly.

Overview

The current supply and demand environment for crude oil and natural gas has resulted in a significant decrease in commodity prices. Based on the sustained decrease in commodity prices through the first quarter of 2015, we expect a challenging 2015. Crude oil prices declined from a high of $107.95 per Bbl in June 2014 to a low of $43.39 in March 2015. 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. Additionally, a portion of our development projects have become uneconomic and contributed to the impairment on the value of our oil and natural gas properties.

Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce, our access to capital and the amount of our cash distributions, as evidenced by our recently announced reduced cash distribution.

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.

Acquisitions have been financed with a combination of proceeds from bank borrowings, issuance of notes, issuances of units and preferred units and cash flow from operations. Post-acquisition activities are focused on evaluating and developing 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.

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 exploitation projects. Our ability to add reserves through acquisitions and development projects is dependent upon many factors including our ability to raise capital, competitively bid on acquisitions, 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” below, we have entered into oil and natural gas derivatives designed to mitigate the effects of price fluctuations covering a portion of our expected production, which allows us to mitigate, but not eliminate, oil 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.

Production and Operating Costs Reporting

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 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 the reported hydrocarbon sales volumes.

Operating Data

The following table sets forth selected unaudited financial and operating data of Legacy for the periods indicated.

	Three Months Ended March 31,	
	2015	2014
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$50,296	$102,055
Natural gas liquids sales	4,192	3,965
Natural gas sales	27,051	19,883
Total revenue	$81,539	$125,903
Expenses:		
Oil and natural gas production, excluding ad valorem taxes	$45,944	$39,638
Ad valorem taxes	$3,276	$2,896
Total oil and natural gas production	$49,220	$42,534
Production and other taxes	$4,218	$7,955
General and administrative, excluding LTIP	$7,781	$6,957
LTIP expense	$1,088	$690
Total general and administrative	$8,869	$7,647
Depletion, depreciation, amortization and accretion	$41,068	$33,697
Commodity derivative cash settlements:		
Oil derivative cash settlements received (paid)	$32,200	$(2,556)
Natural gas derivative cash settlements received (paid)	$8,137	$(1,054)
Production:		
Oil (MBbls)	1,200	1,135
Natural gas liquids (MGal)	9,686	3,362
Natural gas (MMcf)	9,658	3,226
Total (MBoe)	3,040	1,753
Average daily production (Boe/d)	33,778	19,478
Average sales price per unit (excluding derivative cash settlements):		
Oil price (per Bbl)	$41.91	$89.92
Natural gas liquids price (per Gal)	$0.43	$1.18
Natural gas price (per Mcf) (a)	$2.80	$6.16
Combined (per Boe)	$26.82	$71.82
Average sales price per unit (including derivative cash settlements):		
Oil price (per Bbl)	$68.75	$87.66
Natural gas liquids price (per Gal)	$0.43	$1.18
Natural gas price (per Mcf) (a)	$3.64	$5.84
Combined (per Boe)	$40.09	$69.76
Average WTI oil spot price (per Bbl)	$48.57	$98.68
Average Henry Hub natural gas index price (per Mcf)	$2.81	$4.93
Average unit costs per Boe:		
Oil and natural gas production	$15.11	$22.61
Ad valorem taxes	$1.08	$1.65
Production and other taxes	$1.39	$4.54
General and administrative excluding LTIP	$2.56	$3.97
Total general and administrative	$2.92	$4.36

Depletion, depreciation, amortization and accretion	$13.51	$19.22

(a) We primarily report and account for most of 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 are higher than Henry Hub natural gas index prices due to this NGL content.

Results of Operations

Three-Month Period Ended March 31, 2015 Compared to Three-Month Period Ended March 31, 2014

Our revenues from the sale of oil were $50.3 million and $102.1 million for the three-month periods ended March 31, 2015 and 2014, respectively. Our revenues from the sale of NGLs were $4.2 million and $4.0 million for the three-month periods ended March 31, 2015 and 2014, respectively. Our revenues from the sale of natural gas were $27.1 million and $19.9 million for the three-month periods ended March 31, 2015 and 2014, respectively. The $51.8 million decrease in oil revenues reflects the decrease in average realized price of $48.01 per Bbl (53%) partially offset by an increase in oil production of 65 MBbls (6%). This increase in production is related to our purchase of additional oil and natural gas properties during 2014, as well as our ongoing development activities. The decrease in realized oil prices of $48.01 per Bbl during the three months ended March 31, 2015 compared to the same period in 2014 was due to a decline in average West Texas Intermediate ("WTI") crude oil prices of $50.11 per Bbl partially offset by a decrease in realized regional differentials. The $0.2 million increase in NGL sales reflects an increase in NGL production of 6,324 MGals (188%), primarily due to the acquisition of 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. on June 4, 2014 (the "WPX Acquisition") (5,020 MGals), partially offset by a decrease in the realized NGL price of approximately $0.75 per Gal (64%). This decrease in realized prices is a combination of decreased commodity prices as well as the inclusion of the WPX volumes, which receive a lower price than our historical NGL production. The $7.2 million increase in natural gas revenues reflects an increase in our production volumes, partially offset by a decrease in realized natural gas prices. Our natural gas production increased by approximately 6,432 MMcf (199%) primarily due to the WPX Acquisition, which accounted for approximately 6,084 MMcf. Average realized natural gas prices decreased by $3.36 per Mcf (55%) during the three months ended March 31, 2015 compared to the same period in 2014 due to the decline in average Henry Hub natural gas prices of $2.12 per Mcf as well as the inclusion of natural gas from the WPX Acquisition, which receives a lower price than NYMEX Henry Hub pricing. 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. The change in the weighted average regional contribution of our reported natural gas volumes dramatically reduced our realized price per Mcf, on a relative basis.

For the three-month period ended March 31, 2015, we recorded $20.5 million of net gains on oil and natural gas derivatives. Commodity derivative gains and losses represent the changes in fair value of our commodity derivatives during the period and are based on oil and natural gas futures prices. The net gains recognized during the three-month period ended March 31, 2015 are primarily due to the decrease in oil and natural gas prices during the period. For the three-month period ended March 31, 2014, we recorded $15.9 million of net losses on oil and natural gas derivatives. Settlements of such contracts resulted in cash receipts/(payments) of $40.3 million and $(3.6) million during the three months ended March 31, 2015 and 2014, respectively.

Our oil and natural gas production expenses, excluding ad valorem taxes, increased to $45.9 million for the three-month period ended March 31, 2015 from $39.6 million for the three-month period ended March 31, 2014. Production expenses increased primarily due to expenses associated with our acquisitions including $11.3 million related to the WPX Acquisition. While our total production expenses increased during the three-month period ended March 31, 2015, the cost per Boe decreased to $15.11 per Boe for the three-month period ended March 31, 2015 from $22.61 per Boe for the three-month period ended March 31, 2014. This decrease is due in part to reduced expenses across the properties that we have owned prior to the WPX Acquisition and, in larger part, to the large volume of natural gas production related to the WPX Acquisition properties. As natural gas production is typically lower cost production relative to oil production, the increasing natural gas volumes related to this production reduced our expenses on a per Boe basis. Our ad valorem tax expense increased marginally to $3.3 million ($1.08 per Boe) for the three-month period ended March 31, 2015 compared to $2.9 million ($1.65 per Boe) for the three-month period ended March 31, 2014 primarily due to increased well counts from recent acquisitions.

Our production and other taxes were $4.2 million and $8.0 million for the three-month periods ended March 31, 2015 and 2014, respectively. Production and other taxes decreased because of the decline in product prices as well as the inclusion of the WPX Acquisition production which is taxed at a lower rate than our historical production.

Our general and administrative expenses were $8.9 million and $7.6 million for the three-month periods ended March 31, 2015 and 2014, respectively. General and administrative expenses increased $1.2 million primarily due to an increase in salary and benefit expenses related to the hiring of additional personnel to manage our larger asset base.

We incurred depletion, depreciation, amortization and accretion expense, or DD&A, of $41.1 million and $33.7 million for the three-month periods ended March 31, 2015 and 2014, respectively. DD&A increased $7.4 million due primarily to $9.6 million of depletion incurred on the properties acquired in the WPX Acquisition partially offset by lower depletion across much of our asset base due to the reduced depletable basis resulting from the significant impairment realized in the fourth quarter of 2014.

Impairment expense was $209.4 million and $1.4 million for the three-month periods ended March 31, 2015 and 2014, respectively. In the three-month period ended March 31, 2015, we recognized $209.4 million of impairment expense on thirty-three separate producing fields primarily related to the decline in natural gas prices. While we recognized a significant impairment expense in the fourth quarter of 2014, the continued decline in natural gas futures prices during the first quarter of 2015 resulted in additional write-downs, specifically related to our WPX Acquisition properties. Impairment expense for the period ended March 31, 2014 was primarily related to reduced reserve estimates on two unproved properties.

We recorded interest expense of $17.8 million and $13.9 million for the three-month periods ended March 31, 2015 and 2014, respectively. Interest expense increased approximately $3.9 million primarily due to interest expense related to additional senior notes issued subsequent to March 31, 2014.

Non-GAAP Financial Measure

Our management uses Adjusted EBITDA as a tool to provide additional information and metrics relative to the performance of our business. Our 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 companies may not calculate Adjusted EBITDA in the same manner.

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

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

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

- Transaction expenses related to acquisitions.

The following table presents a reconciliation of our consolidated net income (loss) to Adjusted EBITDA for the three and three months ended March 31, 2015 and 2014, respectively.

	Three Months Ended March 31,	
	2015	2014
	(In thousands)	
Net income (loss)	$(228,854)	$526
Plus:		
Interest expense	17,792	13,939
Income tax expense	(747)	314
Depletion, depreciation, amortization and accretion	41,068	33,697
Impairment of long-lived assets	209,402	1,412
(Gain) loss on disposal of assets	1,941	2,301
Equity in income of equity method investees	(79)	8
Unit-based compensation expense	1,088	690
Minimum payments earned in excess of overriding royalty interest(a)	367	333
Equity in EBITDA of equity method investee(b)	119	258
Net (gains) losses on commodity derivatives	(20,480)	15,886
Net cash settlements received (paid) on commodity derivatives	40,337	$(3,610)
Transaction expenses related to acquisitions	25	$55
Adjusted EBITDA	$61,979	$65,809

(a) A portion of minimum payments earned 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 three months ended March 31, 2015 and 2014, respectively, Adjusted EBITDA decreased 6% to $62.0 million from $65.8 million primarily due to the significant decline in commodity prices, partially offset by production from the WPX Acquisition and other recent oil and natural gas property acquisitions as well as higher commodity derivative settlement receipts of approximately $43.9 million.

Capital Resources and Liquidity

Our primary sources of capital and liquidity have been cash flow from operations, the issuance of additional units and preferred units, the issuance of notes, proceeds from bank borrowings or a combination thereof. To date, our primary use of capital has been for 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.

The amounts available for borrowing under our credit facility are subject to a borrowing base which is currently set at $700 million. As of May 6, 2015, we had $587.9 million available for borrowing under our revolving credit facility. Based on their commodity price expectations, our lenders redetermine the borrowing base semi-annually, with the next redetermination scheduled on or around October 2015. Please see "— Cash Flow from Financing Activities — Credit Facility."

Cash Flow from Operations

Our net cash (used in)/provided by operating activities was $(2.2) million and $60.2 million for the three-month periods ended March 31, 2015 and 2014, respectively. The 2015 period was impacted by lower realized commodity prices and higher operating expenses, partially offset by higher production volumes.

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

Cash Flow from Investing Activities

We invested cash capital of $15.1 million for the three-month period ended March 31, 2015. The total includes $1.7 million for the acquisition of oil and natural gas properties in individually immaterial acquisitions as well as $13.4 million for development projects. Our cash capital expenditures were $22.4 million for the three-month period ended March 31, 2014. The total includes $0.6 million for the acquisition of oil and natural gas properties in individually immaterial acquisitions and $21.8 million for development projects.

Our capital expenditure budget, which predominantly consists of drilling, CO_2 injection, recompletion and well stimulation projects, is currently $30 million for the year ending December 31, 2015, of which $13.4 million has been expended during the three months ended March 31, 2015. Our remaining borrowing capacity under our revolving credit facility is $587.9 million as of May 7, 2015. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. We may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, non-operated capital requirements and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner. Based upon current oil and natural gas price expectations for the year ending December 31, 2015, we anticipate that we will have sufficient sources of working capital, including our cash flow from operations and available borrowing capacity under our credit facility, to meet our cash obligations including our remaining planned capital expenditures. Future cash distributions will be at levels to be determined based on cash available for distribution, any remaining borrowing capacity for cash distributions under our credit facility, requirements to repay debt and any other factors the board of directors of our general partner may consider. 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.

We enter into oil and natural gas derivative transactions to reduce the impact of oil and natural gas price volatility on our operations. Currently, we use derivatives to offset price volatility of oil and natural gas prices. For the three-month periods ended March 31, 2015 and 2014, we had favorable (unfavorable) settlements of $40.3 million and $(3.6) million, respectively, related to our commodity derivatives.

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 currently in place as of May 6, 2015, covering the period from April 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 the front-month NYMEX WTI oil, the price on the last trading day of front-month NYMEX Henry Hub natural gas and published West Texas Waha, ANR-Oklahoma and Rocky Mountain CIG prices of natural gas.

Oil Swaps:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl	
April-December 2015	914,735	$79.14	$52.00	- $100.20
2016	228,600	$87.94	$86.30	- $99.85
2017	182,500	$84.75	$84.75	

Natural Gas Swaps:

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu	
April-December 2015	13,963,300	$4.39	$3.98	- $5.82
2016	1,419,200	$4.30	$4.12	- $5.30

We have entered into regional crude oil differential swap contracts in which we have swapped the floating WTI-ARGUS (Midland) crude oil price for floating WTI-ARGUS (Cushing) crude oil price 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 downtime 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 contracts currently in place as of May 7, 2015, covering the period from April 1, 2015 through December 31, 2016:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl	
April-December 2015	2,475,000	$(1.77)	$(1.65)	- $(1.90)
2016	1,464,000	$(1.70)	$(1.65)	- $(1.75)

We have also entered into multiple NYMEX WTI 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 $74.73, $75.00 and $75.00 for the remainder of 2015, 2016 and 2017, respectively.The following table summarizes the three-way oil collar contracts currently in place as of May 7, 2015, covering the period from April 1, 2015 through June 30, 2017:

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
April-December 2015	997,400	$64.87	$89.60	$111.39
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 May 7, 2015, covering the period from January 1, 2016 to December 31, 2018:

Time Period	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 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 $66.78. The following table summarizes these type of enhanced swap contracts currently in place as of May 7, 2015, covering the period from April 1, 2015 to December 31, 2015:

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Swap Price per Bbl
April-December 2015	688,000	$77.01	$93.79

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 the remainder of 2015, 2016 and 2017, respectively.The following table summarizes the three-way natural gas collar contracts currently in place as of May 7, 2015:

Time Period	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
April-December 2015	6,030,000	$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 May 7, 2015, 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:

	April-December 2015	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	9,000,000	$(0.13)
NGPL	360,000	$(0.15)
SoCal	180,000	$0.19
San Juan	360,000	$(0.12)
WAHA	4,500,000	$(0.10)

Cash Flow from Financing Activities

Our net cash used in financing activities was $20.6 million for the three months ended March 31, 2015, compared to net cash used of $22.4 million for the three months ended March 31, 2014. During the three months ended March 31, 2015, total net borrowings under our revolving credit facility were $28.0 million. The proceeds from our net borrowings were used to finance our acquisition and development activities as well as to fund a portion of our distributions to unitholders. We had cash outflow during the three months ended March 31, 2015 in the amount of $42.3 million for distributions to record holders of our units and $4.8 million for distributions to record holders 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"), a portion of which was funded from cash flow from operations with the remainder funded from borrowings under our revolving credit facility. Cash used in financing activities during the three months ended March 31, 2014 included $12.0 million in net repayments and $34.3 million for distributions to unitholders. There were no Series A or Series B Preferred Units outstanding during the three months ended March 31, 2014.

8% Senior Notes Due 2020

On December 4, 2012, we, together with our 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 approximately $286.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by us.

As of March 31, 2015, Legacy was in compliance with all financial and other covenants of the 2020 Senior Notes. If an event of default would occur and were continuing, Legacy would be unable to pay distributions to its unitholders. For further information related to our 2020 Senior Notes please refer to Note 2–Long-Term Debt in the Notes to Condensed Consolidated Financial Statements.

6.625% Senior Notes Due 2021

On May 28, 2013, we, together with our 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. This issuance of our 2021 Senior Notes was at 98.405% of par. We received approximately $240.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by us.

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 $300.0 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.

As of March 31, 2015, Legacy was in compliance with all financial and other covenants of the 2021 Senior Notes. If an event of default would occur and were continuing, Legacy would be unable to pay distributions to its unitholders. For further information related to our 2021 Senior Notes please refer to Note 2–Long-Term Debt in the Notes to Condensed Consolidated Financial Statements.

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”). 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.

As of March 31, 2015, Legacy was in compliance with all covenants of the Current Credit Agreement. If an event of default would occur and were continuing, we would be unable to make borrowings under the Current Credit Agreement, may be unable to make distributions to our unitholders and our financial condition and liquidity would be adversely affected. For further information related to our Current Credit Agreement, please refer to Note 2–Long-Term Debt in the Notes to Condensed Consolidated Financial Statements.

Legacy periodically enters into interest rate swap transactions to mitigate the volatility of interest rates. As of March 31, 2015, Legacy had interest rate swaps on notional amounts of $104 million with a weighted average fixed rate of 2.81%. These swaps mature between April 2015 and November 2015.

Off-Balance Sheet Arrangements

None.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires management to select and apply accounting policies that best provide the framework to report our results of operations and financial position. The selection and application of those policies requires management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

As of March 31, 2015, our critical accounting policies were consistent with those discussed in our Annual Report on Form 10-K for the period ended December 31, 2014.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves, the fair value of assets and liabilities acquired in business combinations, valuation of derivatives, future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations and accrued revenues. Actual results could differ from these estimates.

Recent Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs" ("ASU 2015-03") which changes the presentation of debt issuance costs in financial statements to present such costs as a direct deduction from the related debt liability rather than as an asset. ASU 2015-03 will become effective for public companies during interim and annual reporting periods beginning after December 15, 2015. Early adoption is permitted. We do not expect the adoption of ASU 2015-03 will have a material impact on our consolidated financial statements.

Item 3. 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. These derivative instruments are discussed in Item 1. Financial Statements – Notes to Consolidated Financial Statements – Note 7 Derivative Financial Instruments.

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 market prices applicable to our natural gas production and the prevailing price for crude oil. Pricing for oil and natural gas 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 economy and the regional and international supply of oil and natural gas.

We periodically enter into and anticipate entering into derivative transactions 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 transactions 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 March 31, 2015, the fair market value of our commodity derivative positions was a net asset of $133.2 million based on NYMEX futures prices from April 2015 to December 2018 for both oil and natural gas. As of December 31, 2014, the fair market value of our commodity derivative positions was a net asset of $153.1 million based on NYMEX futures prices from January 2015 to December 2018 for both oil and natural gas. For more discussion about our derivative transactions and to see a table listing the oil and natural gas derivatives from April 2015 through December 2018, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations— Investing Activities."

Interest Rate Risks

At March 31, 2015, we had debt outstanding under its revolving credit facility of $137 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by us under our revolving credit facility for the three-month period ended March 31, 2015 was 4.3%. A 1% increase in LIBOR on our outstanding debt under our revolving credit facility as of March 31, 2015 would result in an estimated $0.33 million increase in annual interest expense assuming our current interest rate hedges remain in place and do not expire. We have entered into interest rate swaps with a weighted-average fixed rate of 2.81% to mitigate the volatility of interest rates on notional amounts of $104 million of floating rate debt, which will expire by November.

Item 4. 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, 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 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 March 31, 2015. 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 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 March 31, 2015, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. 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 1A. Risk Factors.

In addition to the information set forth in this report, you should carefully consider the factors discussed under "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2014, which could materially affect our business, financial condition or future results. The risks described in these reports are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Purchases of Equity Securities

	(a)	(b)	(c)	(d)
Period	Total number of units purchased	Price paid per unit	Total number of units purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value of units) that may yet be purchased under the plans or programs
February 18, 2015	8,051(1)	$13.25	—	—

(1) These units were purchased by the Partnership in satisfaction of certain employee tax withholding obligations at a price of $13.25 per unit, the closing price of Legacy's units on the NASDAQ Global Market on February 18, 2015.

Item 6. Exhibits.

The following documents are filed as a part of this Quarterly Report on Form 10-Q 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 June 17, 2014, Exhibit 3.1)
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 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 May 4, 2012, Exhibit 3.7)
10.1	Fourth Amendment to Third Amended and Restated Credit Agreement, dated February 23, 2015, 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 annual report on Form 10-K (File No. 001-33249) filed February 27, 2015, Exhibit 10.12)
10.2	Non-Executive Chairman Agreement by and among Legacy Reserves GP, LLC, Legacy Reserves Services, Inc. and Cary D. Brown, dated as of February 3, 2015. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on February 6, 2015, Exhibit 10.1)
10.3	Employment Agreement effective as of March 1, 2015, between Kyle M. Hammond and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on February 27, 2015, Exhibit 10.1)
10.4	Second Amendment to Employment Agreement effective as of March 1, 2015, between Legacy Reserves Services, Inc., Paul T. Horne and Legacy Reserves GP, LLC. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on February 27, 2015, Exhibit 10.2)
10.5	Second Amendment to Employment Agreement effective as of March 1, 2015, between Legacy Reserves Services, Inc., Kyle A. McGraw and Legacy Reserves GP, LLC. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on February 27, 2015, Exhibit 10.3)
31.1*	Rule 13a-14(a) Certifications (under Section 302 of the Sarbanes-Oxley Act of 2002)
31.2*	Rule 13a-14(a) Certifications (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)
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.DEF**	XBRL Taxonomy Extenstion Definition Linkbase Document

101.PRE**	XBRL Taxonomy Extenstion Presentation Linkbase Document
101.CAL**	XBRL Taxonomy Extenstion Calculation Linkbase Document
101.LAB**	XBRL Taxonomy Extenstion Label Linkbase Document

* Filed herewith

** Filed electronically herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	LEGACY RESERVES LP
	By: Legacy Reserves GP, LLC, its General Partner
May 8, 2015	By: /s/ James Daniel Westcott James Daniel Westcott Executive Vice President and Chief Financial Officer (On behalf of the Registrant and as Principal Financial Officer)