LEGACY RESERVES LP
Form 10-Q
November 06, 2013

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 September 30, 2013

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

57,513,535 units representing limited partner interests in the registrant were outstanding as of November 5, 2013.

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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 re-completion 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 re-completion. 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.

Re-completion. 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 un-weighted 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

	September 30, 2013	December 31, 2012
	(In thousands)	
Current assets:		
Cash and cash equivalents	$4,053	$3,509
Accounts receivable, net:		
Oil and natural gas	54,039	37,547
Joint interest owners	14,546	27,851
Other	435	551
Fair value of derivatives (Notes 6 and 7)	2,765	15,158
Prepaid expenses and other current assets	4,335	3,294
Total current assets	80,173	87,910
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties using the successful efforts method of accounting	2,220,213	2,078,961
Unproved properties	70,849	65,968
Accumulated depletion, depreciation, amortization and impairment	(696,391)	(573,003)
	1,594,671	1,571,926
Other property and equipment, net of accumulated depreciation and amortization of $5,622 and $4,618, respectively	3,688	2,646
Deposits on pending acquisitions	902	—
Operating rights, net of amortization of $3,901 and $3,531, respectively	3,116	3,486
Fair value of derivatives (Notes 6 and 7)	19,211	15,834
Other assets, net of amortization of $9,529 and $7,909, respectively	18,499	7,804
Investments in equity method investees	4,122	393
Total assets	$1,724,382	$1,689,999

See accompanying notes to condensed consolidated financial statements.

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

	September 30, 2013	December 31, 2012
	(In thousands)	
Current liabilities:		
Accounts payable	$6,058	$1,822
Accrued oil and natural gas liabilities (Note 1)	73,182	50,162
Fair value of derivatives (Notes 6 and 7)	14,124	10,801
Asset retirement obligation (Note 8)	2,338	29,501
Other (Note 10)	19,076	11,437
Total current liabilities	114,778	103,723
Long-term debt (Note 2)	844,307	775,838
Asset retirement obligation (Note 8)	170,768	132,682
Fair value of derivatives (Notes 6 and 7)	2,827	5,590
Other long-term liabilities	1,780	1,886
Total liabilities	1,134,460	1,019,719
Commitments and contingencies (Note 5)		
Unitholders' equity:		
Limited partners' equity - 57,279,449 and 57,038,942 units issued and outstanding at September 30, 2013 and December 31, 2012, respectively	589,833	670,183
General partner's equity (approximately 0.03%)	89	97
Total unitholders' equity	589,922	670,280
Total liabilities and unitholders' equity	$1,724,382	$1,689,999

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$116,396	$70,173	$304,606	$212,097
Natural gas liquids (NGL) sales	3,686	3,492	10,188	10,742
Natural gas sales	16,101	10,531	48,654	33,166
Total revenues	136,183	84,196	363,448	256,005
Expenses:				
Oil and natural gas production	39,701	30,728	112,236	82,023
Production and other taxes	8,385	5,137	22,083	15,040
General and administrative	7,933	6,993	21,279	18,604
Depletion, depreciation, amortization and accretion	37,717	24,833	118,482	73,042
Impairment of long-lived assets	835	7,277	23,352	22,556
(Gain) loss on disposal of assets	758	260	493	(3,064)
Total expenses	95,329	75,228	297,925	208,201
Operating income	40,854	8,968	65,523	47,804
Other income (expense):				
Interest income	227	3	568	11
Interest expense (Notes 2, 6 and 7)	(14,206)	(5,285)	(36,104)	(14,256)
Equity in income of equity method investees	172	30	357	87
Net gains (losses) on commodity derivatives (Notes 6 and 7)	(30,424)	(27,177)	(18,098)	34,084
Other	(16)	(51)	(11)	(87)
Income (loss) before income taxes	(3,393)	(23,512)	12,235	67,643
Income tax expense	(29)	(54)	(608)	(878)
Net income (loss)	$(3,422)	$(23,566)	$11,627	$66,765
Income (loss) per unit - basic and diluted (Note 9)	$(0.06)	$(0.49)	$0.20	$1.40
Weighted average number of units used in computing net income (loss) per unit -				
Basic	57,275	47,869	57,200	47,840
Diluted	57,275	47,869	57,295	47,840

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2013
(UNAUDITED)

	Number of Limited Partner Units (In thousands)	Limited Partner	General Partner	Total Unitholders' Equity
Balance, December 31, 2012	57,039	$670,183	$97	$670,280
Units issued to Legacy Board of Directors for services	18	509	—	509
Unit-based compensation	—	2,549	—	2,549
Vesting of restricted units	69	—	—	—
Offering costs associated with the issuance of units	—	(10)	—	(10)
Units issued in exchange for invesment in equity method investee	153	4,001	—	4,001
Redemption of investment	—	—	(12)	(12)
Distributions to unitholders, $1.725 per unit	—	(99,022)	—	(99,022)
Net income	—	11,623	4	11,627
Balance, September 30, 2013	57,279	$589,833	$89	$589,922

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2013	2012
	(In thousands)	
Cash flows from operating activities:		
Net income	$11,627	$66,765
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	118,482	73,042
Amortization of debt discount and issuance costs	2,826	1,143
Impairment of long-lived assets	23,352	22,556
(Gains) losses on derivatives	14,241	(35,141)
Equity in income of equity method investees	(357)	(87)
Unit-based compensation	1,978	333
(Gain) loss on disposal of assets	493	(3,064)
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, oil and natural gas	(16,492)	328
(Increase) decrease in accounts receivable, joint interest owners	13,305	(3,023)
(Increase) decrease in accounts receivable, other	116	(190)
Increase in other assets	(315)	(619)
Increase in accounts payable	4,236	2,938
Increase in accrued oil and natural gas liabilities	23,020	6,911
Increase (decrease) in other liabilities	4,989	(2,453)
Total adjustments	189,874	62,674
Net cash provided by operating activities	201,501	129,439
Cash flows from investing activities:		
Investment in oil and natural gas properties	(160,836)	(164,322)
Increase in deposits on pending acquisitions	(902)	(930)
Proceeds from (payments related to) sale of assets	(173)	9,102
Investment in other equipment	(2,046)	(1,014)
Goodwill	—	(7,770)
Net cash settlements on commodity derivatives	(4,666)	2,018
Distribution from equity method investee	631	—
Net cash used in investing activities	(167,992)	(162,916)
Cash flows from financing activities:		
Proceeds from long-term debt	664,263	335,000
Payments of long-term debt	(597,000)	(220,000)
Payments of debt issuance costs	(1,184)	(462)
Offering costs associated with the issuance of units	(10)	(2)
Distributions to unitholders	(99,022)	(79,844)
Redemption of investment	(12)	—
Net cash provided by (used in) financing activities	(32,965)	34,692
Net increase in cash and cash equivalents	544	1,215
Cash and cash equivalents, beginning of period	3,509	3,151
Cash and cash equivalents, end of period	$4,053	$4,366

Non-cash investing and financing activities:

Asset retirement obligations associated with property acquisitions	$9,853	$6,036
Asset retirement obligations with properties sold	1,590	—
Units issued in exchange for equity method investee	$4,001	$—
Note receivable received in exchange for the sale of oil and natural gas properties	$11,857	

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 and its affiliated entities are referred to as Legacy, LRLP or the Partnership 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 September 30, 2013 and for the three and nine months ended September 30, 2013 and 2012 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, 2012.

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 the limited partners 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 LRLP’s general partner 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, all property and cash in excess of that required to discharge all liabilities will be distributed to the unitholders and LRLP’s general partner in proportion to their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of Legacy’s assets in liquidation.

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

(b) Accrued Oil and Natural Gas Liabilities

Below are the components of accrued oil and natural gas liabilities as of September 30, 2013 and December 31, 2012.

	September 30, 2013	December 31, 2012
	(In thousands)	
Revenue payable to joint interest owners	$24,996	$24,903
Accrued lease operating expense	12,334	8,507
Accrued capital expenditures	9,672	5,213
Accrued ad valorem tax	13,677	4,806
Other	12,503	6,733
	$73,182	$50,162

(2) Long-Term Debt

Long-term debt consists of the following as of September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	(In thousands)	
Credit Facility due 2016	$314,000	$488,000
8% Senior Notes due 2020	300,000	300,000
6.625% Senior Notes due 2021	250,000	—
	864,000	788,000
Unamortized discount on Senior Notes	(19,693)	(12,162)
Total Long-Term Debt	$844,307	$775,838

Credit Facility

On March 10, 2011, Legacy entered into an amended and restated five-year $1 billion secured revolving credit facility with BNP Paribas as administrative agent (as amended, the "Credit Agreement"). Effective April 20, 2012, Wells Fargo Bank, National Association ("Wells Fargo"), replaced BNP Paribas as administrative agent as a result of the sale of BNP Paribas' energy lending practice to Wells Fargo. Borrowings under the Credit Agreement mature on March 10, 2016. The amount available for borrowing at any one time is limited to the borrowing base with a $2 million sub-limit for letters of credit. In conjunction with Legacy's issuance of 6.625% Senior Notes due 2021 (the "2021 Senior Notes"), on May 28, 2013, the borrowing base under the Credit Agreement was automatically decreased to $737.5 million. The borrowing base is subject to semi-annual redeterminations on or around April 1 and October 1 of each year. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. Legacy also has the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of oil and natural gas properties where the purchase price is greater than 10% of the borrowing base. Under the Credit Agreement, interest on debt outstanding is charged based on Legacy's selection of a one-, two-, three- or six-month LIBOR rate plus 1.75% to 2.75%, or the alternate base rate ("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 0.75% to 1.75% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

The Credit Agreement permits Legacy to issue up to $750 million in aggregate principal amount of senior notes or new debt issued to refinance senior notes, subject to specified conditions in the Credit Agreement, which include that upon the issuance of such senior notes or new debt, the borrowing base will be reduced by an amount equal to (i) in the case of senior notes, 25% of the stated principal amount of the senior notes and (ii) in the case of new debt, 25% of the portion of the new debt that exceeds the original principal amount of the senior notes. As of November 5, 2013, Legacy had $550 million in aggregate principal amount of senior notes outstanding, leaving $200 million available for incremental new issuance subject to the provisions above.

As of September 30, 2013, Legacy had outstanding borrowings of $314 million at a weighted-average interest rate of 2.21% and approximately $423.4 million of availability remaining under the Credit Agreement. For the nine-month period ended September 30, 2013, Legacy paid in cash $9.1 million of interest expense on the Credit Agreement. Legacy's Credit Agreement also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- total debt as of the last day of the most recent quarter to EBITDA (as defined in the Credit Agreement) over the last four quarters of not more than 4.0 to 1.0; and

- consolidated current assets, as of the last day of the most recent quarter and including the unused amount of the total commitments, to consolidated current liabilities as of the last day of the most recent quarter of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under Accounting Standards Codification ("ASC") 815, which includes the current portion of oil, natural gas and interest rate derivatives.

At September 30, 2013, Legacy was in compliance with all covenants of the 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"). The 2020 Senior Notes were issued at 97.848% of par. Legacy received approximately $286.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by Legacy. During the nine months ended September 30, 2013, Legacy amortized $1.0 million of this discount.
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"). The 2021 Senior Notes were issued at 98.405% of par. Legacy received approximately $240.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by Legacy. During the nine months ended September 30, 2013, Legacy amortized $0.2 million of this discount.
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. Legacy's and Legacy Reserves Finance Corporation's obligations under the 2021 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 2021 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 2021 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 2021 Senior Notes.

Interest is payable on June 1 and December 1 of each year, beginning December 1, 2013.

(3) Acquisitions

COG 2012 Acquisition

On December 20, 2012, Legacy purchased certain oil and natural gas properties located primarily in the Permian Basin from COG Operating LLC and Concho Oil and Gas LLC, both wholly-owned subsidiaries of Concho Resources Inc., for a net cash purchase price of $502.6 million. The purchase price was financed with net proceeds from Legacy's November 2012 public offering of units and the 2020 Senior Notes. The effective date of this purchase was October 1, 2012. The operating results from these COG 2012 Acquisition properties have been included from the closing date of their acquisition on December 20, 2012.

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

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

Pro Forma Operating Results

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

	Three Months Ended September 30, 2012		Nine Months Ended September 30, 2012
	(In thousands)		
Revenues	$115,819		$369,601
Net income (loss)	$(18,475	)	$87,883
Income (loss) per unit — basic and diluted	$(0.32	)	$1.54
Units used in computing income per unit:			
Basic and Diluted	57,039		57,010

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

	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
	(In thousands)	
Revenues	$30,683	$86,548
Excess of revenues over direct operating expenses	$21,633	$59,128

(4) Related Party Transactions

Cary D. Brown, Chairman, President and Chief Executive Officer of Legacy's general partner, and Kyle A. McGraw, Director, Executive Vice President and Chief Development Officer of Legacy's general partner, own partnership interests in entities which, in turn, own a combined non-controlling 4.16% interest as limited partners in the partnership which owns the building that Legacy occupies. Monthly rent is $57,170, without respect to property taxes, insurance and operating expenses. The lease expires in September 2015.

During the year ended December 31, 2012, Legacy acquired a 5% working interest in approximately 129,428 acres of prospective Cline Shale acreage from FireWheel Energy, LLC ("FireWheel"), the operator of the properties, for $7.2 million. During the nine months ended September 30, 2013, Legacy acquired an additional 24,510 acres from Firewheel for $1.2 million. FireWheel is a private-equity funded oil and natural gas exploration company in which Alan Brown, son of Dale Brown, a director of Legacy, and brother of Cary D. Brown, is a principal. The interests acquired by Legacy were marketed to numerous industry participants and are governed by an industry standard Participation Agreement and Joint Operating Agreement.

(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 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

As defined in Financial Accounting Standards Board ("FASB") ASC 820-10, fair value is 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. ASC 820-10 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be 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 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 primarily include derivative instruments, such as natural gas derivative swaps for those derivatives indexed to the West Texas Waha, ANR-Oklahoma and CIG indices, enhanced swaps, commodity collars and Midland-Cushing crude oil differential swaps. Although Legacy utilizes third party broker quotes to assess the reasonableness of its prices and valuation techniques, Legacy does not have sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

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

Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy Legacy's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013:

	Fair Value Measurements at September 30, 2013 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)	September 30, 2013
	(In thousands)			
LTIP liability (a)	$—	$(2,085)	$—	$(2,085)
Oil and natural gas swaps	—	(12,360)	8,597	(3,763)
Oil collars	—	—	14,478	14,478
Interest rate swaps	—	(5,690)	—	(5,690)
Total	$—	$(20,135)	$23,075	$2,940

(a)

See Note 10 for further discussion on unit-based compensation expenses and the related 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 estimates the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices, contract parameters and discount rates based on published LIBOR rates and interest swap rates. Due to the lack of an active market for periods beyond one-month from the balance sheet date for our oil price differential swaps, Legacy has reviewed historical differential prices and known economic influences to estimate a reasonable forward curve of future pricing scenarios based upon these factors. Significant changes in the quoted forward prices for commodities and changes in market volatility generally lead to corresponding changes in the fair value measurement of our oil and natural gas derivative contracts. 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 majority of the Partnership's counterparties is mitigated by the fact that such counterparties (or their affiliates) are also bank lenders under the Partnership's revolving credit facility. In addition, Legacy routinely monitors the creditworthiness of its counterparties including those who are no longer lenders under the revolving credit facility. The factors described above are based on significant assumptions made by management, and therefore, 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Beginning balance	$32,386	$41,851	$29,966	$30,054
Total gains (losses)	(8,788)	(8,111)	(2,475)	13,260
Settlements, net	(523)	(5,224)	(4,416)	(14,798)
Ending balance	$23,075	$28,516	$23,075	$28,516
Losses included in earnings relating to derivatives still held as of September 30, 2013 and 2012	$(9,311)	$(13,335)	$(6,891)	$(1,538)

Fair Value on a Non-Recurring Basis

Legacy follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. As it relates to Legacy, ASC 820-10 applies to 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 for which fair value is used.

The asset retirement obligation 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 nine-month period ended September 30, 2013 include:

	Fair Value Measurements at September 30, 2013 Using		
Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(In thousands)		
Assets:			
Impairment (a)	$—	$—	$27,553
Acquisitions (b)	$—	$—	$95,369
Total	$—	$—	$122,922

(a) Legacy utilizes ASC 360-10-35 to periodically review 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 nine-month period ended September 30, 2013, Legacy incurred impairment charges of $23.4 million as oil and natural gas properties with a net cost basis of $50.9 million were written down to their fair value of $27.5 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) Legacy utilizes ASC 805-10 to identify and record the fair value of assets and liabilities acquired in a business combination. During the nine-month period ended September 30, 2013, Legacy acquired oil and natural gas properties, inclusive of unproved acreage acquisitions, with a fair value of $95.4 million in 12 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 $314 million as of September 30, 2013 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 September 30, 2013, the fair values of the 2020 Senior Notes and the 2021 Senior Notes were $304.5 million and $235.9 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 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 to 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. Each of these instruments were costless contracts with no upfront premium paid or payable to our counterparty.

All of these price risk management transactions are considered derivative instruments and are accounted for in accordance with FASB Accounting Standards Codification 815, Derivatives and Hedging Activities ("ASC 815"). 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 as of September 30, 2013 and December 31, 2012 with changes in fair value being recorded in earnings for the three and nine months ended September 30, 2013 and 2012.

By using derivative instruments to mitigate exposures to changes in commodity prices, Legacy is exposed 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 repayment risk. Legacy minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties that are parties to its Credit Agreement.

The following table sets forth a reconciliation of the changes in fair value of Legacy's commodity derivatives for the three and nine months ended September 30, 2013 and 2012.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Beginning fair value of commodity derivatives	$35,187	$56,907	$24,148	$(8,443)
Total gain (loss) - oil derivatives	(31,151)	(24,088)	(18,942)	32,962
Total gain (loss) - natural gas derivatives	727	(3,089)	844	1,122
Oil derivative cash settlements paid (received)	8,006	(2,108)	9,711	10,948
Natural gas derivative cash settlements received	(2,054)	(4,000)	(5,046)	(12,967)
Ending fair value of commodity derivatives	$10,715	$23,622	$10,715	$23,622

As of September 30, 2013, 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
October-December 2013	620,854	$92.90	$80.10 - $107.20
2014	1,776,264	$91.67	$87.50 - $103.75
2015	545,351	$91.98	$88.50 - $100.20
2016	228,600	$87.94	$86.30 - $99.85
2017	182,500	$84.75	$84.75

As of September 30, 2013, 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
October-December 2013	736,000	$(1.47)	$(1.25) - $(1.75)

As of September 30, 2013, 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
October-December 2013	315,560	$66.34	$91.56	$108.15
2014	1,818,880	$66.43	$91.58	$108.62
2015	1,308,500	$64.67	$89.67	$112.21
2016	621,300	$63.37	$88.37	$106.40
2017	72,400	$60.00	$85.00	$104.20

As of September 30, 2013, 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
2015	365,000	$60.00	$80.00	$92.35
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 September 30, 2013, Legacy had the following NYMEX 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
October-December 2013	2,467,851	$4.33	$3.23 - $6.89
2014	8,271,254	$4.32	$3.61 - $6.47
2015	1,339,300	$5.65	$5.14 - $5.82
2016	219,200	$5.30	$5.30

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 pursuant to ASC 815 which establishes accounting and reporting standards requiring that derivative instruments be recorded at fair market value and included in the balance sheet as assets or liabilities.

Legacy does not specifically designate these derivative transactions 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Interest rate swap settlements	$1,436	$1,768	$4,786	$5,244
Unrealized change in fair value - interest rate swaps	(788)	(301)	(3,857)	(1,057)
Total increase to interest expense, net	$648	$1,467	$929	$4,187

The table below summarizes the interest rate swap position as of September 30, 2013:

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at September 30, 2013
(Dollars in thousands)				
$29,000	3.070%	10/16/2007	10/16/2015	$(1,579)
$13,000	3.112%	11/16/2007	11/16/2015	(750)
$12,000	3.131%	11/28/2007	11/28/2015	(684)
$50,000	3.100%	10/10/2008	10/10/2013	(122)
$50,000	0.710%	8/10/2011	8/10/2014	(82)
$50,000	2.295%	12/18/2008	12/18/2013	(257)
$50,000	0.702%	8/10/2011	8/10/2014	(79)
$50,000	2.500%	10/10/2008	10/10/2015	(2,137)
Total fair market value of interest rate derivatives				$(5,690)

(8) Asset Retirement Obligation

ASC 410-20 requires that an asset retirement obligation ("ARO") associated with the retirement of a tangible long-lived asset be 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 nine months ended September 30, 2013 and year ended December 31, 2012:

	September 30, 2013	December 31, 2012
	(In thousands)	
Asset retirement obligation - beginning of period	$162,183	$120,274
Liabilities incurred with properties acquired	9,853	38,857
Liabilities incurred with properties drilled	—	878
Liabilities settled during the period	(1,891)	(2,412)
Liabilities associated with properties sold	(1,590)	—
Current period accretion	4,551	4,586
Asset retirement obligation - end of period	$173,106	$162,183

(9) Earnings Per Unit

The following table sets forth the computation of basic and diluted net earnings per unit:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Income (loss) available to unitholders	$(3,422)	$(23,566)	$11,627	$66,765
Weighted average number of units outstanding	57,275	47,869	57,200	47,840
Effect of dilutive securities:				
Restricted and phantom units	—	—	95	—
Weighted average units and potential units outstanding	57,275	47,869	57,295	47,840
Basic and diluted earnings (loss) per unit	$(0.06)	$(0.49)	$0.20	$1.40

For the three and nine months ended September 30, 2013, 425,195 and 330,116 restricted and phantom units, respectively, were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect. For the three and nine months ended September 30, 2012, 227,477 restricted units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect.

(10) Unit-Based Compensation

Long-Term Incentive Plan

On March 15, 2006, a Long-Term Incentive Plan (“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 covering an aggregate of 2,000,000 units. As of September 30, 2013, grants of awards net of forfeitures and, in the case of UARs and phantom units, historical exercises covering 1,626,924 units had been made, comprised of 266,014 unit option awards, 615,043 UARs, 438,486 restricted unit awards, 195,143 phantom unit awards and 112,238 unit awards. The LTIP is administered by the compensation committee (the “Compensation Committee”) of the board of directors of Legacy’s general partner.

ASC 718 requires companies to measure the cost of employee services in exchange for an award of equity instruments 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, ASC 718 stipulates that “if an entity that nominally has the choice of settling awards by issuing stock predominately settles in cash, or if the 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 unit options, UARs and phantom unit awards in cash, Legacy accounts for unit options, UARs and certain phantom unit awards by utilizing the liability method as described in ASC 718. 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. However, during 2013, the Compensation Committee revised the executive compensation plan and amended certain historical phantom unit award agreements to eliminate the Compensation Committee's option of settling phantom unit awards for executive officers in cash. Due to the elimination of the cash settlement option, Legacy now accounts for executive phantom unit awards under the equity method as described in ASC 718. Legacy treated the amendment as a cancellation of the historical awards and a grant of new awards in the period, though the award amounts and vesting terms remained unchanged.

Unit Appreciation Rights and Unit Options

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

During the year ended December 31, 2012, Legacy issued 82,400 UARs to employees which vest ratably over a three-year period and 60,336 UARs to employees which vest at the end of a three-year period. During the nine-month period ended September 30, 2013, Legacy issued 123,650 UARs to employees which vest ratably over a three-year period and 74,506 UARs to employees which vest at the end of a three-year period. All UARs granted in 2012 and 2013 expire seven years from the grant date and are exercisable when they vest.

For the nine-month periods ended September 30, 2013 and 2012, Legacy recorded $0.7 million and $0.5 million, respectively, of compensation expense due to the change in liability from December 31, 2012 and 2011, respectively, based on its use of the Black-Scholes model to estimate the September 30, 2013 and 2012 fair value of these UARs and unit options (see Note 6). As of September 30, 2013, there was a total of approximately $1.6 million of unrecognized compensation costs related to the unexercised and non-vested portion of these UARs. At September 30, 2013, this cost was expected to be recognized over a weighted-average period of approximately 2.3 years. Compensation expense is based upon the fair value as of September 30, 2013 and is recognized as a percentage of the service period satisfied. Since Legacy's trading history does not yet match the term of the outstanding UAR and unit option awards, it has used an estimated volatility factor of approximately 51% based upon the historical trends of a representative group of publicly-traded companies in the energy industry and employed the Black-Scholes model to estimate the September 30, 2013 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 3.7%. As required by ASC 718, Legacy will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.32 per unit.

A summary of UAR and unit option activity for the nine months ended September 30, 2013 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2013	516,219	$ 24.71		
Granted	198,156	26.41		
Exercised	(83,666)	19.92		
Forfeited	(15,666)	26.46		
Outstanding at September 30, 2013	615,043	$ 25.86	5.3	$ 1,063,605
UARs and unit options exercisable at September 30, 2013	235,154	$ 23.63	3.9	$ 897,780

The following table summarizes the status of Legacy’s non-vested UARs since January 1, 2013:

	Non-Vested UARs	
	Number of Units	Weighted-Average Exercise Price
Non-vested at January 1, 2013	347,650	$ 26.73
Granted	198,156	26.41
Vested	(151,917)	24.96
Forfeited	(14,000)	27.35
Non-vested at September 30, 2013	379,889	$ 27.25

Legacy has used a weighted-average risk-free interest rate of 1.4% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at September 30, 2013 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.

	Nine Months Ended September 30, 2013	
Expected life (years)	5.52	
Risk free interest rate	1.4	%
Annual distribution rate per unit	$2.32	
Volatility	51	%

Phantom Units

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

On September 21, 2009, the board of directors of Legacy's general partner, 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. 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 this compensation policy, 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 February 1, 2012 and February 2, 2012, the Compensation Committee approved the award of 30,828 subjective, or service-based, phantom units and 57,189 objective, or performance based, phantom units to Legacy's executive officers. On March 7, 2013, the Compensation Committee approved the award of 46,430 subjective, or service-based, phantom units and 76,723 objective, or performance based, phantom units to Legacy's executive officers.

Compensation expense related to the phantom units and associated DERs was $0.7 million and $1.5 million for the nine months ended September 30, 2013 and 2012, respectively.

Restricted Units

During the year ended December 31, 2012, Legacy issued an aggregate of 173,645 restricted units to both non-executive employees and certain executives not previously covered under the executive compensation plan. These restricted units awarded mostly vest ratably over a three-year period, ratably over a two-year period or cliff-vest at the end of a five year period, all beginning on or around the date of grant. During the nine-month period ended September 30, 2013, Legacy issued an aggregate of 84,528 restricted units to non-executive employees. These restricted units awarded vest either ratably over a three or five-year period, all beginning on or around the date of grant. Compensation expense related to restricted units was $1.7 million and $1.2 million for the nine months ended September 30, 2013 and 2012, respectively. As of September 30, 2013, there was a total of $5.4 million of unrecognized compensation expense related to the unvested portion of these restricted units. At September 30, 2013, this cost was expected to be recognized over a weighted-average period of 2.8 years. Pursuant to the provisions of ASC 718, Legacy's issued units, as reflected in the accompanying consolidated balance sheet at September 30, 2013, do not include 236,052 units related to unvested restricted unit awards.

Board and Additional Executive Units

On May 9, 2012, Legacy granted and issued 3,509 units to each of its five non-employee directors and 2,500 units to an executive officer. The value of each unit was $28.34 at the time of issuance. On May 14, 2013, Legacy granted and issued 3,715 units to each of its five non-employee directors. The value of each unit was $27.39 at the time of issuance.

(11) Subsidiary Guarantors

On September 6, 2011, we filed a post-effective amendment to 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 are currently unregistered but we have agreed to register them by January 8, 2014 or be subject to certain penalties. The Partnership's 2021 Senior Notes were issued in a private offering on May 28, 2013 and are currently unregistered but we have agreed to register them by July 2, 2014 or be subject to certain penalties. 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 October 22, 2013, Legacy's board of directors approved a distribution of $0.585 per unit payable on November 14, 2013 to unitholders of record on November 1, 2013, representing an increase of $0.005 per unit over the last quarterly distribution.

On October 15, 2013, the borrowing base under our Credit Agreement was increased to $800.0 million from $737.5 million. The next redetermination is scheduled on or around April 2014.

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 capital expenditures;
- the level of cash distributions to our unitholders;
- our future operating results; and
- our plans, objectives, expectations and intentions.

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

The forward-looking statements contained in this document are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this document are not guarantees of future performance, and our expectations may not be realized or the forward-looking events and circumstances may not occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in Legacy’s Annual Report on Form 10-K for the year ended December 31, 2012 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

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 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.

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.

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, re-completing 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 exploitation 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 significant portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. We regularly monitor 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, if any, on any redetermination of our borrowing base under our revolving credit facility.

Legacy does not specifically designate derivative instruments as cash flow hedges; therefore, the changes in fair value associated with these instruments are 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 and determine if any wells or properties should be shut-in or re-completed.

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 and are reported with production costs. 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$116,396	$70,173	$304,606	$212,097
Natural gas liquids sales	3,686	3,492	10,188	10,742
Natural gas sales	16,101	10,531	48,654	33,166
Total revenue	$136,183	$84,196	$363,448	$256,005
Expenses:				
Oil and natural gas production	$36,659	$28,207	$103,308	$75,067
Ad valorem taxes	$3,042	$2,521	$8,928	$6,956
Total oil and natural gas production	$39,701	$30,728	$112,236	$82,023
Production and other taxes	$8,385	$5,137	$22,083	$15,040
General and administrative excluding LTIP	$6,648	$4,855	$17,665	$14,934
LTIP expense	$1,285	$2,138	$3,614	$3,670
Total general and administrative	$7,933	$6,993	$21,279	$18,604
Depletion, depreciation, amortization and accretion	$37,717	$24,833	$118,482	$73,042
Commodity derivative cash settlements:				
Oil derivative cash settlements received (paid)	$(8,006)	$2,108	$(9,711)	$(10,948)
Natural gas derivative cash settlements received	$2,054	$4,000	$5,046	$12,967
Production:				
Oil (MBbls)	1,141	840	3,343	2,418
Natural gas liquids (MGal)	3,527	3,821	9,740	10,938
Natural gas (MMcf)	3,714	2,571	10,909	7,774
Total (MBoe)	1,844	1,359	5,393	3,974
Average daily production (Boe/d)	20,043	14,772	19,755	14,504
Average sales price per unit (excluding derivative cash settlements):				
Oil price (per Bbl)	$102.01	$83.54	$91.12	$87.72
Natural gas liquids price (per Gal)	$1.05	$0.91	$1.05	$0.98
Natural gas price (per Mcf)	$4.34	$4.10	$4.46	$4.27
Combined (per Boe)	$73.85	$61.95	$67.39	$64.42
Average sales price per unit (including derivative cash settlements):				
Oil price (per Bbl)	$95.00	$86.05	$88.21	$83.19
Natural gas liquids price (per Gal)	$1.05	$0.91	$1.05	$0.98
Natural gas price (per Mcf)	$4.89	$5.65	$4.92	$5.93
Combined (per Boe)	$70.62	$66.45	$66.53	$64.93
NYMEX oil index prices per Bbl:				
Beginning of period	$96.56	$84.96	$91.82	$98.83
End of period	$102.33	$92.19	$102.33	$92.19
NYMEX gas index prices per Mcf:				
Beginning of period	$3.57	$2.82	$3.35	$2.99
End of period	$3.56	$3.32	$3.56	$3.32
Average unit costs per Boe:				

Oil and natural gas production	$19.88	$20.76	$19.16	$18.89
Ad valorem taxes	$1.65	$1.86	$1.66	$1.75
Production and other taxes	$4.55	$3.78	$4.09	$3.78
General and administrative excluding LTIP	$3.61	$3.57	$3.28	$3.76
Total general and administrative	$4.30	$5.15	$3.95	$4.68
Depletion, depreciation, amortization and accretion	$20.45	$18.27	$21.97	$18.38

Results of Operations

Three-Month Period Ended September 30, 2013 Compared to Three-Month Period Ended September 30, 2012

Legacy's revenues from the sale of oil were $116.4 million and $70.2 million for the three-month periods ended September 30, 2013 and 2012, respectively. Legacy's revenues from the sale of NGLs were $3.7 million and $3.5 million for the three-month periods ended September 30, 2013 and 2012, respectively. Legacy's revenues from the sale of natural gas were $16.1 million and $10.5 million for the three-month periods ended September 30, 2013 and 2012, respectively. The $46.2 million increase in oil revenues reflects the increase in oil production of 301 MBbls (36%) as well as an increase in average realized price of $18.47 per Bbl (22%). 250 MBbls of this increase is related to Legacy's purchase of oil and natural gas properties in the COG 2012 Acquisition, and, to a lesser extent, production from our other acquisitions of additional oil and natural gas properties and our development activities during late 2012 and 2013. These factors were partially offset by third party infrastructure issues that inhibited our oil and natural gas production in the Permian Basin to a greater extent during the third quarter of 2013 compared to the same period in 2012. The improvement in realized oil prices of $18.47 per Bbl during the three months ended September 30, 2013 compared to the same period in 2012 was due to an improvement in West Texas Intermediate ("WTI") crude oil prices of $13.66 per Bbl as well as improved crude oil differentials in the Permian Basin and Rocky Mountain regions, including an improvement in the Midland-to-Cushing/WTI differential of $1.46 per Bbl. The $0.2 million increase in NGL sales reflects an increase in realized NGL price of approximately $0.14 (15%) partially offset by a decrease in NGL production of 294 MGals (8%). The $5.6 million increase in natural gas revenues reflects an increase in our natural gas production volumes combined with an increase in our realized natural gas prices. Our natural gas production increased by approximately 1,143 MMcf (44%) primarily due to acquisitions of oil and natural gas properties, most notably our COG 2012 Acquisition (1,157 MMcf), as well as our development activities which were partially offset by third party infrastructure issues that impacted our natural gas production in the Permian Basin to a greater extent during the third quarter of 2013 compared to the same period in 2012. While we have received assurances that these third party infrastructure issues are being addressed, based on historical experience, we anticipate that these issues may continue to inhibit our oil and natural gas production and negatively impact our results of operations, but are unable to quantify any such potential impact. Average realized natural gas prices increased by $0.24 per Mcf (6%) during the three months ended September 30, 2013 compared to the same period in 2012, as a significant increase in dry natural gas prices was partially offset by lower, positive differentials due to the curtailment of a portion of our NGL-rich natural gas production and lower NGL prices in the Permian Basin. We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content contained within those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin and for Legacy as a whole are higher than NYMEX Henry Hub natural gas prices due to this NGL content.

For the three-month period ended September 30, 2013, Legacy recorded $30.4 million of net losses on oil and natural gas derivatives. Inclusive in this amount were net cash payments of $6.0 million from cash settlements of oil and natural gas derivative contracts during the period. 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. Accordingly, the net loss recognized during the three-month period ended September 30, 2013 is primarily due to the increase in oil prices during the period. For the three-month period ended September 30, 2012, Legacy recorded $27.2 million of net losses on oil and natural gas derivatives. Inclusive in this amount were net cash receipts of $6.1 million from cash settlements of oil and natural gas derivative contracts.

Legacy's oil and natural gas production expenses, excluding ad valorem taxes, increased to $36.7 million ($19.88 per Boe) for the three-month period ended September 30, 2013 from $28.2 million ($20.76 per Boe) for the three-month period ended September 30, 2012. Production expenses increased primarily due to $6.7 million of expenses related to properties acquired in the COG 2012 Acquisition, the acquisition of additional oil and natural gas properties and, to a lesser extent, expenses associated with Legacy's development activities. Legacy’s ad valorem tax expense increased to $3.0 million ($1.65 per Boe) for the three-month period ended September 30, 2013 compared to $2.5 million ($1.86 per Boe) for the three-month period ended September 30, 2012, due to increased well counts from recent acquisitions, primarily the COG 2012 Acquisition.

Legacy’s production and other taxes were $8.4 million and $5.1 million for the three-month periods ended September 30, 2013 and 2012, respectively. Production and other taxes increased because of increased production volumes related to the COG 2012 Acquisition and other recent acquisitions and increased product prices, as production and other taxes as a percentage of revenue remained relatively unchanged during the three-month period ended September 30, 2013 compared to the same period in 2012.

Legacy’s general and administrative expenses were $7.9 million and $7.0 million for the three-month periods ended September 30, 2013 and 2012, respectively. General and administrative expenses increased $0.9 million primarily due to a $1.9

million increase in salary and benefit expenses related to the hiring of additional personnel to manage our larger asset base, partially offset by a decrease in unit-based compensation of $0.9 million.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $37.7 million and $24.8 million for the three-month periods ended September 30, 2013 and 2012, respectively. DD&A increased primarily due to approximately $10.2 million of depletion expense related to the properties acquired in the COG 2012 Acquistion.

Impairment expense was $0.8 million and $7.3 million for the three-month periods ended September 30, 2013 and 2012, respectively. In the three-month period ended September 30, 2013, Legacy recognized $0.8 million of impairment expense on seven separate producing fields primarily related to lower forecasted natural gas prices, which reduced the future expected cash flows. Impairment expense for the period ended September 30, 2012 was primarily related to a reduction in the carrying value to the estimated fair market value of a property owned by Legacy held for sale.

Legacy recorded interest expense of $14.2 million and $5.3 million for the three-month periods ended September 30, 2013 and 2012, respectively. Interest expense increased approximately $8.9 million primarily due to $10.6 million of interest expense related to the senior notes issued in December 2012 and May 2013. This increase was partially offset by increased income of $0.5 million related to the mark-to-market of our interest rate swaps, lower interest rate swap settlements of $0.3 million due to swaps that expired during 2013, and lower interest expense attributable to our revolving credit agreement due to a lower outstanding balance during the third quarter of 2013 compared to the same period in 2012.

Nine-Month Period Ended September 30, 2013 Compared to Nine-Month Period Ended September 30, 2012

Legacy's revenues from the sale of oil were $304.6 million and $212.1 million for the nine-month periods ended September 30, 2013 and 2012, respectively. Legacy's revenues from the sale of NGLs were $10.2 million and $10.7 million for the nine-month periods ended September 30, 2013 and 2012, respectively. Legacy's revenues from the sale of natural gas were $48.7 million and $33.2 million for the nine-month periods ended September 30, 2013 and 2012, respectively. The $92.5 million increase in oil revenues reflects the increase in oil production of 925 MBbls (38%) combined with an increase in average realized price of $3.40 per Bbl (4%). The increase in production is due primarily to 776 MBbls of oil production related to Legacy's purchase of oil and natural gas properties in the COG 2012 Acquisition, and, to a lesser extent, production from our other acquisitions of additional oil and natural gas properties and our development activities partially offset by a greater impact from third party infrastructure issues during the nine months ended September 30, 2013 compared to the same period in 2012. The increase in average realized oil price of $3.40 per Bbl was primarily caused by an increase in the average WTI crude oil price of $2.04 per Bbl (2%), and, to a lesser extent, improvements in our crude oil differentials in the Rocky Mountain and Permian Basin regions during the nine-month period ended September 30, 2013 compared to the same period during 2012. The $0.6 million decrease in NGL sales reflects a decrease in NGL production of approximately 1,198 MGals (11%) due to third-party infrastructure issues as well as natural production declines in the Texas Panhandle, all of which were partially offset by an increase in average realized price of $0.07 per gallon (7%). The $15.5 million increase in natural gas revenues reflects an increase in our natural gas production volumes combined with an increase in our realized natural gas prices. Our natural gas production increased by approximately 3,135 MMcf (40%) primarily due to our acquisitions, most notably our COG 2012 Acquisition (3,553 MMcf), as well as our development activities which were partially offset by third party infrastructure issues that impacted our natural gas production in both the Permian Basin and the Texas Panhandle to a greater degree during the nine months ended September 30, 2013 compared to the same period in 2012. While we have received assurances that these third party infrastructure issues are being addressed, based on historical experience, we anticipate that these issues may continue to inhibit our oil and natural gas production and negatively impact our results of operations, but are unable to quantify any such potential impact. Average realized natural gas prices increased by $0.19 per Mcf (4%) during the nine-months ended September 30, 2013 compared to the same period in 2012, as a significant increase in dry natural gas prices was mostly offset by lower, positive differentials due to the curtailment of a portion of our NGL-rich natural gas production and lower NGL prices in the Permian Basin. We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content contained within those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin and for Legacy as a whole are higher than NYMEX Henry Hub natural gas prices due to this NGL content.

For the nine-month period ended September 30, 2013, Legacy recorded $18.1 million of net losses on oil and natural gas derivatives. Inclusive in this amount were net cash payments of $4.7 million from cash settlements of oil and natural gas derivative contracts during the period. 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. Accordingly, the net loss recognized during the nine-months ended September 30, 2013 is primarily due to the increase in both oil and natural gas prices during the period. For the nine-month period ended September 30, 2012, Legacy recorded $34.1 million of net gains on oil and natural gas derivatives. Inclusive in this amount were net cash receipts of $2.0 million from cash settlements of oil and natural gas derivative contracts.

Legacy’s oil and natural gas production expenses, excluding ad valorem taxes, increased to $103.3 million ($19.16 per Boe) for the nine-month period ended September 30, 2013 from $75.1 million ($18.89 per Boe) for the nine-month period ended September 30, 2012. Production expenses increased primarily due to $20.5 million of expenses related to properties acquired in the COG 2012 Acquisition, the acquisition of additional oil and natural gas properties and, to a lesser extent, expenses associated with Legacy's development activities. Legacy’s ad valorem tax expense increased to $8.9 million ($1.66 per Boe) for the nine-month period ended September 30, 2013 compared to $7.0 million ($1.75 per Boe) for the nine-month period ended September 30, 2012, due to increased well counts from acquisitions, primarily the COG 2012 Acquisition.

Legacy’s production and other taxes were $22.1 million and $15.0 million for the nine-month periods ended September 30, 2013 and 2012, respectively. Production and other taxes increased because of increased production volumes related to the COG 2012 Acquisition, other acquisitions and development activities, as well as increased product prices, as production and other taxes as a percentage of revenue increased marginally during the nine-month period ended September 30, 2013 compared to the same period in 2012.

Legacy’s general and administrative expenses were $21.3 million and $18.6 million for the nine-month periods ended September 30, 2013 and 2012, respectively. General and administrative expenses increased $2.7 million primarily due to a $5.1 million increase in salary and benefit expenses related to the hiring of additional personnel to manage our larger asset base, partially offset by an increase in overhead recovery of $3.0 million.

Legacy’s depletion, depreciation, amortization and accretion expense, or DD&A, was $118.5 million and $73.0 million for the nine-month periods ended September 30, 2013 and 2012, respectively. DD&A increased primarily due to approximately $37.7 million of depletion expense related to the properties acquired in the COG 2012 Acquistion.

Impairment expense was $23.4 million and $22.6 million for the nine-month periods ended September 30, 2013 and 2012, respectively. In the nine-month period ended September 30, 2013, Legacy recognized $23.4 million of impairment expense on forty-four separate producing fields primarily related to lower forecasted oil and natural gas prices, which reduced the future expected cash flows. Impairment expense for the period ended September 30, 2012 was related to lower oil and natural gas prices, impairment of goodwill recognized on an acquisition of oil and natural gas properties during the period, and a reduction in the carrying value of a property owned by Legacy held for sale.

Legacy recorded interest expense of $36.1 million and $14.3 million for the nine-month periods ended September 30, 2013 and 2012, respectively. Interest expense increased approximately $21.8 million primarily due to $24.5 million of interest expense related to the senior notes issued in December 2012 and May 2013, partially offset by increased income of $2.8 million related to the mark-to-market of our interest rate swaps.

Non-GAAP Financial Measure

For the three months ended September 30, 2013 and 2012, respectively, Adjusted EBITDA (as defined below) increased 54% to $76.2 million from $49.5 million primarily due to increased production from the COG 2012 Acquisition, other acquisitions and development activities, as well as higher realized commodity prices. These factors were partially offset by higher commodity derivative settlement payments of approximately $12.1 million as well as higher expenses and taxes.

For the nine-months ended September 30, 2013 and 2012, respectively, Adjusted EBITDA (as defined below) increased 43% to $208.5 million from $146.0 million primarily due to increased production from the COG 2012 Acquisition, other acquisitions and development activities, as well as higher realized commodity prices. These factors were partially offset by higher commodity derivative settlement payments of approximately $6.7 million as well as higher expenses and taxes.

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