LEGACY RESERVES LP
Form 10-Q
August 07, 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 June 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 1400 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

57,516,665 units representing limited partner interests in the registrant were outstanding as of August 6, 2013.

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

Bcf. Billion cubic feet.

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

Boe/d. Barrels of oil equivalent per day.

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

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

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

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

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

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

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

Hydrocarbons. Oil, 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 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

	June 30, 2013	December 31, 2012
	(In thousands)	
Current assets:		
Cash and cash equivalents	$3,991	$3,509
Accounts receivable, net:		
Oil and natural gas	45,615	37,547
Joint interest owners	18,781	27,851
Other	411	551
Fair value of derivatives (Notes 6 and 7)	8,518	15,158
Prepaid expenses and other current assets	5,081	3,294
Total current assets	82,397	87,910
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties using the successful efforts method of accounting	2,192,538	2,078,961
Unproved properties	70,265	65,968
Accumulated depletion, depreciation, amortization and impairment	(659,918)	(573,003)
	1,602,885	1,571,926
Other property and equipment, net of accumulated depreciation and amortization of $5,281 and $4,618, respectively	3,442	2,646
Operating rights, net of amortization of $3,778 and $3,531, respectively	3,239	3,486
Fair value of derivatives (Notes 6 and 7)	31,579	15,834
Other assets, net of amortization of $8,964 and $7,909, respectively	19,068	7,804
Investments in equity method investees	4,180	393
Total assets	$1,746,790	$1,689,999

See accompanying notes to condensed consolidated financial statements.

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

	June 30, 2013	December 31, 2012
	(In thousands)	
Current liabilities:		
Accounts payable	$4,161	$1,822
Accrued oil and natural gas liabilities (Note 1)	69,824	50,162
Fair value of derivatives (Notes 6 and 7)	8,232	10,801
Asset retirement obligation (Note 8)	2,338	29,501
Other (Note 10)	9,321	11,437
Total current liabilities	93,876	103,723
Long-term debt (Note 2)	852,872	775,838
Asset retirement obligation (Note 8)	169,313	132,682
Fair value of derivatives (Notes 6 and 7)	3,155	5,590
Other long-term liabilities	1,857	1,886
Total liabilities	1,121,073	1,019,719
Commitments and contingencies (Note 5)		
Unitholders' equity:		
Limited partners' equity - 57,274,363 and 57,038,942 units issued and outstanding at June 30, 2013 and December 31, 2012, respectively	625,627	670,183
General partner's equity (approximately 0.03%)	90	97
Total unitholders' equity	625,717	670,280
Total liabilities and unitholders' equity	$1,746,790	$1,689,999

See accompanying notes to condensed consolidated financial statements.

Page 7

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$97,852	$65,787	$188,209	$141,925
Natural gas liquids (NGL) sales	3,161	3,524	6,503	7,250
Natural gas sales	17,373	9,851	32,553	22,634
Total revenues	118,386	79,162	227,265	171,809
Expenses:				
Oil and natural gas production	37,184	26,406	72,535	51,294
Production and other taxes	6,771	4,687	13,698	9,904
General and administrative	7,064	5,161	13,346	11,611
Depletion, depreciation, amortization and accretion	39,113	25,370	80,765	48,209
Impairment of long-lived assets	20,774	13,978	22,517	15,279
Gain on disposal of assets	(46)	(313)	(265)	(3,324)
Total expenses	110,860	75,289	202,596	132,973
Operating income	7,526	3,873	24,669	38,836
Other income (expense):				
Interest income	334	4	342	8
Interest expense (Notes 2, 6 and 7)	(11,206)	(4,636)	(21,898)	(8,971)
Equity in income of equity method investees	140	32	185	57
Realized and unrealized net gains on commodity derivatives (Notes 6 and 7)	25,330	84,350	12,325	61,261
Other	(2)	(68)	4	(36)
Income before income taxes	22,122	83,555	15,627	91,155
Income tax expense	(368)	(613)	(578)	(824)
Net income	$21,754	$82,942	$15,049	$90,331
Income per unit - basic and diluted (Note 9)	$0.38	$1.73	$0.26	$1.89
Weighted average number of units used in computing net income per unit -				
Basic	57,246	47,850	57,162	47,826
Diluted	57,349	47,850	57,195	47,826

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
FOR THE SIX MONTHS ENDED JUNE 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	—	1,564	—	1,564
Vesting of restricted units	64	—	—	—
Offering costs associated with the issuance of units	—	(11)	—	(11)
Units issued in exchange for invesment in equity method investee	153	4,001	—	4,001
Redemption of investment	—	—	(12)	(12)
Distributions to unitholders, $1.145 per unit	—	(65,663)	—	(65,663)
Net income	—	15,044	5	15,049
Balance, June 30, 2013	57,274	$625,627	$90	$625,717

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2013	2012
	(In thousands)	
Cash flows from operating activities:		
Net income	$15,049	$90,331
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	80,765	48,209
Amortization of debt discount and issuance costs	1,828	753
Impairment of long-lived assets	22,517	15,279
Gains on derivatives	(15,394)	(62,018)
Equity in income of equity method investees	(185)	(57)
Unit-based compensation	1,061	(814)
Gain on disposal of assets	(265)	(3,324)
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, oil and natural gas	(8,068)	5,044
(Increase) decrease in accounts receivable, joint interest owners	9,070	(1,259)
(Increase) decrease in accounts receivable, other	140	(239)
Increase in other assets	(1,377)	(5)
Increase (decrease) in accounts payable	2,339	(750)
Increase in accrued oil and natural gas liabilities	19,662	1,043
Decrease in other liabilities	(4,266)	(2,634)
Total adjustments	107,827	(772)
Net cash provided by operating activities	122,876	89,559
Cash flows from investing activities:		
Investment in oil and natural gas properties	(132,618)	(134,342)
Proceeds from sale of assets	294	9,016
Investment in other equipment	(1,459)	(692)
Goodwill	—	(7,770)
Net cash settlements on commodity derivatives	1,285	(4,090)
Distribution from equity method investee	399	—
Net cash used in investing activities	(132,099)	(137,878)
Cash flows from financing activities:		
Proceeds from long-term debt	561,263	263,000
Payments of long-term debt	(485,000)	(161,000)
Payments of debt issuance costs	(872)	(293)
Offering costs associated with the issuance of units	(11)	(2)
Distributions to unitholders	(65,663)	(52,955)
Redemption of investment	(12)	—
Net cash provided by financing activities	9,705	48,750
Net increase in cash and cash equivalents	482	431
Cash and cash equivalents, beginning of period	3,509	3,151
Cash and cash equivalents, end of period	$3,991	$3,582

Non-cash investing and financing activities:

Asset retirement obligations associated with property acquisitions	$9,812	$5,434
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 June 30, 2013 and for the three and six months ended June 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 June 30, 2013 and December 31, 2012.

	June 30, 2013	December 31, 2012
	(In thousands)	
Revenue payable to joint interest owners	$30,181	$24,903
Accrued lease operating expense	11,556	8,507
Accrued capital expenditures	9,080	5,213
Accrued ad valorem tax	10,200	4,806
Other	8,807	6,733
	$69,824	$50,162

(2) Long-Term Debt

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

	June 30, 2013	December 31, 2012
	(In thousands)	
Credit Facility due 2016	$323,000	$488,000
8% Senior Notes due 2020	300,000	300,000
6.625% Senior Notes due 2021	250,000	—
	873,000	788,000
Unamortized discount on Senior Notes	(20,128)	(12,162)
Total Long-Term Debt	$852,872	$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 August 6, 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 June 30, 2013, Legacy had outstanding borrowings of $323 million at a weighted-average interest rate of 2.22% and approximately $414.4 million of availability remaining under the Credit Agreement. For the six-month period ended

June 30, 2013, Legacy paid in cash $6.7 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 June 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 six months ended June 30, 2013, Legacy amortized $0.7 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 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 six months ended June 30, 2013, Legacy amortized $0.04 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 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 June 30, 2012	Six Months Ended June 30, 2012
	(In thousands)	
Revenues	$110,620	$244,782
Net income	$85,172	$103,801
Income per unit — basic and diluted	$1.49	$1.82
Units used in computing income per unit:		
Basic	57,020	56,996
Diluted	57,020	56,996

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 June 30, 2013	Six Months Ended June 30, 2013
	(In thousands)	
Revenues	$29,269	$55,864
Excess of revenues over direct operating expenses	$20,320	$37,495

(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 six months ended June 30, 2013, Legacy acquired an additional 14,761 acres from Firewheel for $0.7 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.

In 2007, Raven Resources, LLC ("Raven") filed a lawsuit against Legacy Reserves Operating LP ("Legacy") in the 385th District Court, Midland County, Texas (Cause No. CV 46609). On November 10, 2009, the District Court granted summary judgment in favor of Legacy. Raven appealed the District Court's judgment, and on April 15, 2011, the Eleventh Court of Appeals, in an appeal styled Raven Resources, LLC, Appellant v. Legacy Reserves Operating LP, Appellee (Case No. 11-09-00348-CV), reversed and rendered in part and reversed and remanded in part the District Court's decision. Legacy filed a motion for rehearing, and on March 15, 2012, the Court of Appeals reconsidered its prior decision and affirmed the District Court's judgment in favor of Legacy.

On April 27, 2012, Raven filed a petition for review with the Supreme Court of Texas. On March 8, 2013, the Texas Supreme Court denied Raven's petition for review. On April 8, 2013, Raven filed a motion for rehearing with the Texas Supreme Court requesting that the Texas Supreme Court reconsider its decision. On May 10, 2013, the Texas Supreme Court denied Raven's motion for rehearing. The Eleventh Court of Appeals issued a mandate to the District Court on June 14, 2013, affirming the District Court's judgment in favor of Legacy.

(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 June 30, 2013:

	Fair Value Measurements at June 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)	Total Carrying Value as of June 30, 2013
	(In thousands)			
LTIP liability (a)	$—	$(2,153)	$—	$(2,153)
Oil and natural gas swaps	—	2,801	9,751	12,552
Oil collars	—	—	22,635	22,635
Interest rate swaps	—	(6,477)	—	(6,477)
Total	$—	$(5,829)	$32,386	$26,557

(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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands)			
Beginning balance	$18,814	$25,648	$29,966	$30,054
Total gains	13,534	21,322	6,313	21,370
Settlements, net	38	(5,119)	(3,893)	(9,573)
Ending balance	$32,386	$41,851	$32,386	$41,851
Change in unrealized losses included in earnings relating to derivatives still held as of June 30, 2013 and 2012	$13,572	$16,203	$2,420	$11,797

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 six-month period ended June 30, 2013 include:

	Fair Value Measurements at June 30, 2013 Using		
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
Description	(Level 1)	(Level 2)	(Level 3)
	(In thousands)		
Assets:			
Impairment (a)	$—	$—	$27,186
Acquisitions (b)	$—	$—	$93,263
Total	$—	$—	$120,449

(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 six-month period ended June 30, 2013, Legacy incurred impairment charges of $22.5 million as oil and natural gas properties with a net cost basis of $49.7 million were written down to their fair value of $27.2 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 six-month period ended June 30, 2013, Legacy acquired oil and natural gas properties, inclusive of unproved acreage acquisitions, with a fair value of $93.3 million in 10 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 $323 million as of June 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. The fair values of the 2020 Senior Notes and the 2021 Senior Notes were $308.8 million and $239.4 million, respectively, as of June 30, 2013. 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 June 30, 2013 and December 31, 2012 with changes in fair value being recorded in earnings for the three and six months ended June 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.

For the three and six months ended June 30, 2013 and 2012, Legacy recognized realized and unrealized gains and losses related to its oil and natural gas derivative transactions. The net gains from derivative activities were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands)			
Crude oil derivative contract settlements	$(1,934)	$(6,855)	$(1,705)	$(13,057)
Natural gas derivative contract settlements	584	4,817	2,990	8,967
Total commodity derivative contract settlements	(1,350)	(2,038)	1,285	(4,090)
Unrealized change in fair value - oil contracts	21,638	93,385	13,914	70,107
Unrealized change in fair value - natural gas contracts	5,042	(6,997)	(2,874)	(4,756)
Total unrealized change in fair value of commodity derivative contracts	26,680	86,388	11,040	65,351
Total realized and unrealized gains on commodity derivative contracts	$25,330	$84,350	$12,325	$61,261

As of June 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:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July-December 2013	1,117,509	$91.43	$80.10 - $103.75
2014	1,739,764	$91.66	$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 June 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:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July-December 2013	1,472,000	$(1.47)	$(1.25) - $(1.75)

As of June 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:

Calendar Year	Volumes (Bbls)	Average Short Put Price	Average Long Put Price	Average Short Call Price
July-December 2013	631,120	$66.34	$91.56	$108.15
2014	1,453,880	$65.54	$90.73	$110.65
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 June 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:

Calendar Year	Volumes (Bbls)	Average Long Put Price	Average Short Put Price	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 June 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:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
July-December 2013	5,030,302	$4.31	$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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands)			
Interest rate swap settlements	$1,569	$1,784	$3,350	$3,476
Unrealized change in fair value - interest rate swaps	(1,624)	(470)	(3,069)	(757)
Total increase to interest expense, net	$(55)	$1,314	$281	$2,719

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

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at June 30, 2013
(Dollars in thousands)				
$29,000	3.070%	10/16/2007	10/16/2015	$(1,681)
$13,000	3.112%	11/16/2007	11/16/2015	(789)
$12,000	3.131%	11/28/2007	11/28/2015	(728)
$50,000	3.100%	10/10/2008	10/10/2013	(479)
$50,000	0.710%	8/10/2011	8/10/2014	(39)
$50,000	2.295%	12/18/2008	12/18/2013	(481)
$50,000	0.702%	8/10/2011	8/10/2014	(35)
$50,000	2.500%	10/10/2008	10/10/2015	(2,245)
Total fair market value of interest rate derivatives				$(6,477)

(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 six months ended June 30, 2013 and year ended December 31, 2012:

	June 30, 2013	December 31, 2012
	(In thousands)	
Asset retirement obligation - beginning of period	$162,183	$120,274
Liabilities incurred with properties acquired	9,812	38,857
Liabilities incurred with properties drilled	—	878
Liabilities settled during the period	(1,690)	(2,412)
Liabilities associated with properties sold	(1,590)	—
Current period accretion	2,936	4,586
Asset retirement obligation - end of period	$171,651	$162,183

(9) Earnings Per Unit

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands)			
Income available to unitholders	$21,754	$82,942	$15,049	$90,331
Weighted average number of units outstanding	57,246	47,850	57,162	47,826
Effect of dilutive securities:				
Restricted and phantom units	103	—	33	—
Weighted average units and potential units outstanding	57,349	47,850	57,195	47,826
Basic and diluted earnings per unit	$0.38	$1.73	$0.26	$1.89

For the three and six months ended June 30, 2013, 321,866 and 391,663 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 six months ended June 30, 2012, 146,477 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 June 30, 2013, grants of awards net of forfeitures and, in the case of UARs and phantom units, historical exercises covering 1,559,465 units had been made, comprised of 266,014 unit option awards, 552,970 UARs, 433,100 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 six-month period ended June 30, 2013, Legacy issued 84,250 UARs to employees which vest ratably over 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 six-month periods ended June 30, 2013 and 2012, Legacy recorded $0.5 million and $(0.4) million, respectively, of compensation expense/(income) 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 June 30, 2013 and 2012 fair value of these UARs and unit options (see Note 6). As of June 30, 2013, there was a total of approximately $1.2 million of unrecognized compensation costs related to the unexercised and non-vested portion of these UARs. At June 30, 2013, this cost was expected to be recognized over a weighted-average period of approximately 2.1 years. Compensation expense is based upon the fair value as of June 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 June 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 4.6%. As required by ASC 718, Legacy will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.30 per unit.

A summary of UAR and unit option activity for the six months ended June 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	84,250		25.70		
Exercised	(39,833	)	20.13		
Forfeited	(7,666	)	24.85		
Outstanding at June 30, 2013	552,970		$ 25.19	4.9	$1,214,363
UARs and unit options exercisable at June 30, 2013	155,737		$ 22.04	3.4	$821,915

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	84,250		25.70
Vested	(28,667	)	28.02
Forfeited	(6,000	)	26.48
Non-vested at June 30, 2013	397,233		$ 26.42

Legacy has used a weighted-average risk-free interest rate of 1.2% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at June 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.

	Six Months Ended June 30, 2013	
Expected life (years)	5.11	
Risk free interest rate	1.2	%

Annual distribution rate per unit	$2.30	
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 $0.3 million and $0.7 million for the six months ended June 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 six-month period ended June 30, 2013, Legacy issued an aggregate of 76,778 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 $1.1 million and $0.7 million for the six months ended June 30, 2013 and 2012, respectively. As of June 30, 2013, there was a total of $5.8 million of unrecognized compensation expense related to the unvested portion of these restricted units. At June 30, 2013, this cost was expected to be recognized over a weighted-average period of 3.0 years. Pursuant to the provisions of ASC 718, Legacy's issued units, as reflected in the accompanying consolidated balance sheet at June 30, 2013, do not include 235,752 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 July 22, 2013, Legacy’s board of directors approved a distribution of $0.58 per unit payable on August 14, 2013 to unitholders of record on August 1, 2013, representing an increase of $0.005 per unit over the last quarterly distribution.

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 mark-to-market adjustment reflecting the unrealized gain or loss associated with these instruments is recorded in current earnings.

Production and Operating Costs Reporting

We strive to increase our production levels to maximize our revenue and cash available for distribution. Additionally, we continuously monitor our operations to ensure that we are incurring operating costs at the optimal level 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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$97,852	$65,787	$188,209	$141,925
Natural gas liquids sales	3,161	3,524	6,503	7,250
Natural gas sales	17,373	9,851	32,553	22,634
Total revenue	$118,386	$79,162	$227,265	$171,809
Expenses:				
Oil and natural gas production	$34,265	$23,877	$66,650	$46,859
Ad valorem taxes	$2,919	$2,529	$5,885	$4,435
Total oil and natural gas production	$37,184	$26,406	$72,535	$51,294
Production and other taxes	$6,771	$4,687	$13,698	$9,904
General and administrative excluding LTIP	$5,720	$5,186	$11,017	$10,079
LTIP expense	$1,344	$(25)	$2,329	$1,532
Total general and administrative	$7,064	$5,161	$13,346	$11,611
Depletion, depreciation, amortization and accretion	$39,113	$25,370	$80,765	$48,209
Realized commodity derivative settlements:				
Realized losses on oil derivatives	$(1,934)	$(6,855)	$(1,705)	$(13,057)
Realized gains on natural gas derivatives	$584	$4,817	$2,990	$8,967
Production:				
Oil (MBbls)	1,089	790	2,203	1,578
Natural gas liquids (MGal)	3,320	3,626	6,213	7,116
Natural gas (MMcf)	3,649	2,545	7,194	5,203
Total (MBoe)	1,776	1,301	3,550	2,615
Average daily production (Boe/d)	19,516	14,297	19,613	14,368
Average sales price per unit (excluding derivatives):				
Oil price (per Bbl)	$89.85	$83.27	$85.43	$89.94
Natural gas liquids price (per Gal)	$0.95	$0.97	$1.05	$1.02
Natural gas price (per Mcf)	$4.76	$3.87	$4.53	$4.35
Combined (per Boe)	$66.66	$60.85	$64.02	$65.70
Average sales price per unit (including realized derivative gains/losses):				
Oil price (per Bbl)	$88.08	$74.60	$84.66	$81.67
Natural gas liquids price (per Gal)	$0.95	$0.97	$1.05	$1.02
Natural gas price (per Mcf)	$4.92	$5.76	$4.94	$6.07
Combined (per Boe)	$65.90	$59.28	$64.38	$64.14
NYMEX oil index prices per Bbl:				
Beginning of period	$97.23	$103.02	$91.82	$98.83
End of period	$96.56	$84.96	$96.56	$84.96
NYMEX gas index prices per Mcf:				
Beginning of period	$4.02	$2.13	$3.35	$2.99
End of period	$3.57	$2.82	$3.57	$2.82
Average unit costs per Boe:				
Oil and natural gas production	$19.29	$18.35	$18.77	$17.92

Ad valorem taxes	$1.64	$1.94	$1.66	$1.70
Production and other taxes	$3.81	$3.60	$3.86	$3.79
General and administrative excluding LTIP	$3.22	$3.99	$3.10	$3.85
Total general and administrative	$3.98	$3.97	$3.76	$4.44
Depletion, depreciation, amortization and accretion	$22.02	$19.50	$22.75	$18.44

Results of Operations

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

Legacy's revenues from the sale of oil were $97.9 million and $65.8 million for the three-month periods ended June 30, 2013 and 2012, respectively. Legacy's revenues from the sale of NGLs were $3.2 million and $3.5 million for the three-month periods ended June 30, 2013 and 2012, respectively. Legacy's revenues from the sale of natural gas were $17.4 million and $9.9 million for the three-month periods ended June 30, 2013 and 2012, respectively. The $32.1 million increase in oil revenues reflects the increase in oil production of 299 MBbls (38%) as well as an increase in average realized price of $6.58 per Bbl (8%). 262 MBbls of this increase is in connection with 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 during 2012 and 2013. These factors were partially offset by third-party plant downtime and line pressure issues that not only inhibited our natural gas production but also impacted our oil production in the Permian Basin. While West Texas Intermediate ("WTI") crude oil prices improved by $0.76 per Bbl during the three months ended June 30, 2013 compared to the same period in 2012, the improvement in realized oil prices of $6.58 per Bbl during the second quarter of 2013 was primarily due to improved crude oil differentials in the Permian Basin and Rocky Mountain regions, most notably an improvement in the Midland-to-Cushing/WTI differential of $4.76 per Bbl. The $0.4 million decrease in NGL sales reflects a decrease in NGL production of approximately 306 MGals (8%) as well as a decrease in average realized price of $0.02 per gallon (2%). The $7.5 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 1,104 MMcf (43%) primarily due to our 2012 acquisitions of oil and natural gas properties, most notably our COG 2012 Acquisition (1,202 MMcf), as well as our development activities which were partially offset by third-party plant downtime, line pressure and other gathering issues that impacted our natural gas production in the Permian Basin. Average realized natural gas prices increased by $0.89 per Mcf (23%) during the three months ended June 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 June 30, 2013, Legacy recorded $25.3 million of net gains on oil and natural gas derivatives comprised of realized losses of $1.4 million from net cash settlements of oil and natural gas derivative contracts and net unrealized gains of $26.7 million. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives that will be settled in future periods. Legacy had realized losses of $1.9 million from net cash settlements of its oil derivatives during the three months ended June 30, 2013. In addition, Legacy had unrealized net gains of $21.6 million from oil derivatives primarily because oil futures prices decreased during the three-month period ended June 30, 2013. Due to these oil price movements, the associated net asset related to our oil derivatives at June 30, 2013 increased relative to the net asset balance as of March 31, 2013, resulting in the recording of the corresponding unrealized gain. Legacy had realized gains of $0.6 million from net cash settlements of its natural gas derivatives during the three months ended June 30, 2013. In addition, Legacy had unrealized net gains from natural gas derivatives of $5.0 million because the NYMEX natural gas futures prices decreased during the three-month period ended June 30, 2013. Due to this decrease in natural gas prices during the quarter, the net asset attributable to Legacy's outstanding natural gas derivatives increased resulting in the recording of the corresponding unrealized gain. For the three-month period ended June 30, 2012, Legacy recorded $84.4 million of net gains on oil and natural gas derivatives, comprised of realized losses of $2.0 million from net cash settlements of oil and natural gas derivative contracts and net unrealized gains of $86.4 million.

Legacy’s oil and natural gas production expenses, excluding ad valorem taxes, increased to $34.3 million ($19.29 per Boe) for the three-month period ended June 30, 2013 from $23.9 million ($18.35 per Boe) for the three-month period ended June 30, 2012. Production expenses increased primarily due to $6.8 million of expenses related to properties acquired in the COG 2012 Acquisition, the acquisition of additional oil and natural gas properties in 2012 and, to a lesser extent, expenses associated with Legacy's development activities. Legacy’s ad valorem tax expense increased to $2.9 million ($1.64 per Boe) for the three-month period ended June 30, 2013 compared to $2.5 million ($1.94 per Boe) for the three-month period ended June 30, 2012, due to increased well counts from recent acquisitions, primarily the COG 2012 Acquisition.

Legacy’s production and other taxes were $6.8 million and $4.7 million for the three-month periods ended June 30, 2013 and 2012, respectively. Production and other taxes increased because of increased production volumes related to the COG 2012 Acquisition and other 2012 acquisitions and increased product prices, as production and other taxes as a percentage of revenue remained relatively unchanged during the three-month period ended June 30, 2013 compared to the same period in 2012.

Legacy's general and administrative expenses were $7.1 million and $5.2 million for the three-month periods ended June 30, 2013 and 2012, respectively. General and administrative expenses increased $1.9 million primarily due to a $1.4 million increase in unit-based compensation and, to a lesser extent, increased salary and benefit expenses related to the hiring of additional personnel to manage our larger asset base.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $39.1 million and $25.4 million for the three-month periods ended June 30, 2013 and 2012, respectively. DD&A increased primarily due to approximately $11.1 million of depletion expense related to the properties acquired in the COG 2012 Acquistion.

Impairment expense was $20.8 million and $14.0 million for the three-month periods ended June 30, 2013 and 2012, respectively. In the three-month period ended June 30, 2013, Legacy recognized $20.8 million of impairment expense on thirty separate producing fields primarily related to lower forecasted oil prices, which reduced the future expected cash flows. Impairment expense for the period ended June 30, 2012, was related to declining oil prices during the period as well as impairment of goodwill recognized on an acquisition of oil and natural gas properties during the period.

Legacy recorded interest expense of $11.2 million and $4.6 million for the three-month periods ended June 30, 2013 and 2012, respectively. Interest expense increased approximately $6.6 million primarily due to $7.6 million of interest expense related to the senior notes issued in December 2012 and May 2013, respectively, partially offset by increased income of $1.2 million related to the mark-to-market of our interest rate swaps.

Six-Month Period Ended June 30, 2013 Compared to Six-Month Period Ended June 30, 2012

Legacy's revenues from the sale of oil were $188.2 million and $141.9 million for the six-month periods ended June 30, 2013 and 2012, respectively. Legacy's revenues from the sale of NGLs were $6.5 million and $7.3 million for the six-month periods ended June 30, 2013 and 2012, respectively. Legacy's revenues from the sale of natural gas were $32.6 million and $22.6 million for the six-month periods ended June 30, 2013 and 2012, respectively. The $46.3 million increase in oil revenues reflects the increase in oil production of 625 MBbls (40%) partially offset by a decrease in average realized price of $4.51 per Bbl (5%). The increase in production is due primarily to 533 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 during 2012 and 2013 partially offset by third-party plant downtime and line pressure issues. The decrease in average realized oil price was primarily caused by a decrease in the average WTI crude oil price of $3.92 per Bbl (4%), and, to a lesser extent, an increase in our crude oil differential during the six-month period ended June 30, 2013 compared to the same period during 2012. The $0.7 million decrease in NGL sales reflects a decrease in NGL production of approximately 903 MGals (13%) due to third-party plant downtime and line pressure 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 $0.03 per gallon (3%). The $9.9 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 1,991 MMcf (38%) primarily due to our 2012 acquisitions, most notably our COG 2012 Acquisition (2,409 MMcf), as well as our development activities which were partially offset by third-party plant downtime and line pressure issues that impacted our natural gas production in both the Permian Basin and the Texas Panhandle. Average realized natural gas prices increased by $0.18 per Mcf (4%) during the six-months ended June 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 six-month period ended June 30, 2013, Legacy recorded $12.3 million of net gains on oil and natural gas derivatives comprised of realized gains of $1.3 million from net cash settlements of oil and natural gas derivative contracts and net unrealized gains of $11.0 million. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives that will be settled in future periods. Legacy had realized losses of $1.7 million from net cash settlements of its oil derivatives during the six-months ended June 30, 2013. In addition, Legacy had unrealized net gains of $13.9 million from oil derivatives primarily due to a decrease in oil futures prices that was partially offset by an improved Midland-to-Cushing/WTI differential. Due to these oil price and differential movements, the associated net asset related to our oil derivatives at June 30, 2013 increased relative to the net asset balance as of December 31, 2012, resulting in the recording of the corresponding unrealized gain. Legacy had realized gains of $3.0 million from net cash settlements of its natural gas derivatives during the six-months ended June 30, 2013. In addition, Legacy had unrealized net losses from natural gas derivatives of $2.9 million, which primarily reflects an offset to realized gains and a corresponding reduction of the net asset attributable to Legacy's outstanding natural gas derivatives. Natural gas futures prices were relatively stable, with only a slight decline between December 31, 2012 and June 30, 2013. For the six-month period ended June 30, 2012, Legacy recorded $61.3 million of net gains on oil and natural gas derivatives, comprised of realized losses of $4.1 million from net cash settlements of oil and natural gas derivative contracts and net unrealized gains of $65.4 million.

Legacy’s oil and natural gas production expenses, excluding ad valorem taxes, increased to $66.7 million ($18.77 per Boe) for the six-month period ended June 30, 2013 from $46.9 million ($17.92 per Boe) for the six-month period ended June 30, 2012. Production expenses increased primarily due to $13.9 million of expenses related to properties acquired in the COG 2012 Acquisition, the acquisition of additional oil and natural gas properties in 2012 and, to a lesser extent, expenses associated with Legacy's development activities. Legacy’s ad valorem tax expense increased to $5.9 million ($1.66 per Boe) for the six-month period ended June 30, 2013 compared to $4.4 million ($1.70 per Boe) for the six-month period ended June 30, 2012, due to increased well counts from acquisitions, primarily the COG 2012 Acquisition.

Legacy’s production and other taxes were $13.7 million and $9.9 million for the six-month periods ended June 30, 2013 and 2012, respectively. Production and other taxes increased because of increased production volumes related to the COG 2012 Acquisition and other 2012 acquisitions, as production and other taxes as a percentage of revenue increased marginally during the six-month period ended June 30, 2013 compared to the same period in 2012.

Legacy’s general and administrative expenses were $13.3 million and $11.6 million for the six-month periods ended June 30, 2013 and 2012, respectively. General and administrative expenses increased $1.7 million primarily due to a $0.8 million increase in unit-based compensation as well as increased salary and benefit expenses related to the hiring of additional personnel to manage our larger asset base.

Legacy’s depletion, depreciation, amortization and accretion expense, or DD&A, was $80.8 million and $48.2 million for the six-month periods ended June 30, 2013 and 2012, respectively. DD&A increased primarily due to approximately $27.4 million of depletion expense related to the properties acquired in the COG 2012 Acquistion.

Impairment expense was $22.5 million and $15.3 million for the six-month periods ended June 30, 2013 and 2012, respectively. In the six-month period ended June 30, 2013, Legacy recognized $22.5 million of impairment expense on thirty-nine separate producing fields primarily related to lower forecasted oil prices, which reduced the future expected cash flows. Impairment expense for the period ended June 30, 2012 was related to declining natural gas prices during the period as well as impairment of goodwill recognized on an acquisition of oil and natural gas properties during the period.

Legacy recorded interest expense of $21.9 million and $9.0 million for the six-month periods ended June 30, 2013 and 2012, respectively. Interest expense increased approximately $12.9 million primarily due to $13.9 million of interest expense related to the senior notes issued in December 2012 and May 2013, partially offset by increased income of $2.3 million related to the mark-to-market of our interest rate swaps.

Non-GAAP Financial Measure

For the three months ended June 30, 2013 and 2012, respectively, Adjusted EBITDA (as defined below) increased 67% to $67.9 million from $40.8 million primarily due to increased production from the COG 2012 Acquisition and other 2012 acquisitions as well as increased realized commodity prices and lower realized derivative settlement payments of approximately $0.7 million. These factors were partially offset by higher production expenses, ad valorem taxes and production and other taxes.

For the six-months ended June 30, 2013 and 2012, respectively, Adjusted EBITDA (as defined below) increased 37% to $132.3 million from $96.4 million primarily due to increased production from the COG 2012 Acquisition and other 2012 acquisitions as well as increased realized derivative settlement receipts of approximately $5.4 million. These factors were partially offset by slightly lower realized commodity prices as well as higher production expenses, ad valorem taxes and production and other 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;
- (Gain) loss on sale of partnership investment;
- (Gain) loss on disposal of assets;
- Equity in (income) loss of equity method investees;
- Unit-based compensation expense (benefit) related to LTIP unit awards accounted for under the equity or liability methods;
- Minimum payments earned in excess of overriding royalty interest;
- EBITDA applicable to equity method investee; and
- Unrealized (gains) losses on oil and natural gas derivatives.

The following table presents a reconciliation of Legacy's consolidated net income (loss) to Adjusted EBITDA for the three and six months ended June 30, 2013 and 2012, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(Dollars in thousands)			
Net income	$21,754	$82,942	$15,049	$90,331
Plus:				
Interest expense	11,206	4,636	21,898	8,971
Income tax expense	368	613	578	824
Depletion, depreciation, amortization and accretion	39,113	25,370	80,765	48,209
Impairment of long-lived assets	20,774	13,978	22,517	15,279
Gain on disposal of assets	(46)	(313)	(265)	(3,324)
Equity in income of equity method investees	(140)	(32)	(185)	(57)
Unit-based compensation expense (benefit)	1,344	(24)	2,329	1,532
Minimum payments earned in excess of overriding royalty interest(a)	10	—	410	—
EBITDA applicable to equity method investee(b)	226	—	226	—
Unrealized gains on oil and natural gas derivatives	(26,680)	(86,388)	(11,040)	(65,351)
Adjusted EBITDA	$67,929	$40,782	$132,282	$96,414

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

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

Capital Resources and Liquidity

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

We continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in maintaining and growing reserves and production will be highly dependent on capital resources available to us and our success in acquiring and developing additional reserves. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our credit facility, if available, or obtain additional debt or equity financing. Further, our revolving credit facility and our 2020 Senior Notes and 2021 Senior Notes impose specific restrictions on our ability to obtain additional debt financing. Please see “Financing Activities.” Based upon current oil and natural gas price expectations and our extensive commodity derivatives positions for the year ending December 31, 2013, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our credit facility will provide us sufficient working capital to meet our currently planned capital expenditures and future cash distributions at levels to be determined based on cash available for distribution, any remaining borrowing capacity for cash distributions under our credit facility, requirements to repay debt, and any other factors the board of directors of our general partner may consider.

The amounts available for borrowing under our credit facility are subject to a borrowing base, which is currently set at $737.5 million. As of August 6, 2013, we had $426.4 million available for borrowing under our revolving credit facility. Based on their commodity price expectations, our lenders redetermine the borrowing base semi-annually, with the next redetermination scheduled on or around October 2013. Please see “— Financing Activities — Our Revolving Credit Facility.”

Cash Flow from Operations

Legacy’s net cash provided by operating activities was $122.9 million and $89.6 million for the six-month periods ended June 30, 2013 and 2012, respectively. The 2013 period was favorably impacted by higher production volumes primarily related to the COG 2012 Acquisition, partially offset by slightly lower realized commodity prices and higher expenses. In addition, the net cash amounts for 2013 and 2012 do not include cash settlements received (paid) of $1.3 million and $(4.1) million, respectively, from our commodity derivative transactions.

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

Investing Activities

Legacy’s cash capital expenditures were $132.6 million for the six-month period ended June 30, 2013. The total includes $93.3 million for the acquisition of oil and natural gas properties in 10 individually immaterial acquisitions, $38.2 million for development projects and $1.2 million of exploratory capital expenditures. Legacy’s cash capital expenditures were $134.3 million for the six-month period ended June 30, 2012. The total includes $105.3 million for the acquisition of oil and natural gas properties in nine individually immaterial acquisitions and $28.9 million for development projects.

Our capital expenditure budget, which predominantly consists of drilling, re-completion and capital workover projects, is currently $90.0 million for the year ending December 31, 2013, of which $39.4 million has been expended during the six-months ended June 30, 2013. Our remaining borrowing capacity under our revolving credit facility is $426.4 million as of August 6, 2013. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. We may defer a portion of our planned capital expenditures until later periods or accelerate projects planned for future periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner. Based upon current oil and natural gas price expectations for the year ending December 31, 2013, we anticipate that we will have sufficient sources of working capital, including our cash flow from operations and available borrowing capacity under our credit facility, to meet our cash obligations including our remaining planned capital expenditures of $50.6 million. Future cash distributions will be at levels to be determined based on cash available for distribution, any remaining borrowing capacity for cash distributions under our credit facility, requirements to repay debt and any other factors the board of directors of our general partner may consider. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

We enter into oil and natural gas derivative transactions to reduce the impact of oil and natural gas price volatility on our operations. Currently, we use derivatives to offset price volatility on NYMEX oil and natural gas prices, which do not include the additional net discount to NYMEX WTI that we typically experience in the Permian Basin. For the six-month periods ended June 30, 2013 and 2012 we had favorable (unfavorable) cash settlements of $1.3 million and $(4.1) million, respectively, related to our commodity derivatives. At June 30, 2013, we had in place oil and natural gas derivatives covering significant portions of our estimated 2013 through 2018 oil, NGL and natural gas production.

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

The following tables summarize, for the periods indicated, our oil and natural gas derivatives currently in place as of August 6, 2013, covering the period from July 1, 2013 through December 31, 2018. We use derivatives, including swaps, enhanced swaps and 3-way collars, as our mechanism for offsetting the cash flow effects of changes in commodity prices whereby we pay the counterparty floating prices and receive fixed prices from the counterparty, which serves to reduce the effects on cash flow of the floating prices we are paid by purchasers of our oil and natural gas. These transactions are mostly settled based upon the monthly average closing price of the front-month NYMEX WTI oil contract price at Cushing, Oklahoma, and published West Texas Waha, Rocky Mountain CIG and ANR-Oklahoma prices of natural gas with settlements occuring on the fifth day of the production month.

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl		
July-December 2013	1,177,909	$91.80	$80.10	-	$103.75
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		

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu		
July-December 2013	5,030,302	$4.31	$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		

We have entered into regional crude oil differential swap contracts in which we have swapped the floating WTI-ARGUS (Midland) crude oil price for floating WTI-ARGUS (Cushing) less a fixed-price differential. As noted above, we typically receive a discount to the NYMEX WTI crude oil price at the point of sale. Due to refinery downtimes and limited takeaway capacity that impacted the Permian Basin, the difference between the WTI-ARGUS (Midland) price, which is the price we receive on almost all of our Permian crude oil production, and the WTI-ARGUS (Cushing) price reached historic highs in late 2012 and early 2013. We entered into these differential swaps to negate a portion of this volatility. The following table summarizes the oil differential swap contracts currently in place as of August 6, 2013, covering the period from July 1, 2013 through December 31, 2013:

Time Period	Volumes (Bbls)	Price Range per Bbl

		Average Price per Bbl		
July-December 2013	1,472,000	$(1.47)	$(1.25)	- $(1.75)

We have also entered into multiple NYMEX WTI crude oil derivative three-way collar contracts. Each contract combines a long put, a short put and a short call. The use of the short put allows us to buy a put and sell a call at higher prices, thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk. If the market price is below the long put fixed price but above the short put fixed price, a three-way collar allows us to settle for the long put fixed price. A three-way collar also allows us to settle for WTI market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. The following table summarizes the three-way oil collar contracts currently in place as of August 6, 2013, covering the period from July 1, 2013 through June 30, 2017:

Calendar Year	Volumes (Bbls)	Average Short Put Price	Average Long Put Price	Average Short Call Price
July-December 2013	631,120	$66.34	$91.56	$108.15
2014	1,453,880	$65.54	$90.73	$110.65
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

We have also entered into multiple NYMEX WTI crude oil derivative enhanced swap contracts. Each contract combines buying a lower-priced put, selling a higher-priced put, and using the net proceeds from these positions to simultaneously obtain a swap at above market prices (“enhanced swap price”). If the market price is at or above the higher-priced short put, this contract allows us to settle at the enhanced swap price. If the market price is below the higher-priced short put but above the lower-priced long put, this contract allows us to settle for the market price plus the spread between the enhanced swap price and the higher-priced short put. If the market price is at or below the lower-priced long put, this contract allows us to settle for the lower-priced long put plus the spread between the enhanced swap price and the higher-priced short put. The following summarizes the enhanced swap contracts currently in place as of August 6, 2013, covering the period from January 1, 2015 to December 31, 2018.

Calendar Year	Volumes (Bbls)	Average Long Put Price	Average Short Put Price	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

Financing Activities

Legacy’s net cash provided by financing activities was $9.7 million for the six months ended June 30, 2013, compared to $48.8 million for the six months ended June 30, 2012. During the six months ended June 30, 2013, total net repayments under our revolving credit facility were $165.0 million while we raised $241.3 million in proceeds, net of original issue discount and fees paid to initial purchasers in our private offering of 6.625% Senior Notes due 2021, resulting in total net borrowings of $76.3 million. The borrowings under the credit facility were used to finance our acquisition and development activities. Additionally, Legacy had cash outflow during the six months ended June 30, 2013 in the amount of $65.7 million for distributions to unitholders which was funded from cash flow from operations. Cash provided by financing activities during the six months ended June 30, 2012, included $102.0 million in net borrowings under our revolving credit facility and $53.0 million for distributions to unitholders.

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. Legacy used the net proceeds from this offering to fund a portion of the consideration paid for the COG 2012 Acquisition, as further described in Note 3 to the Notes to the Condensed Consolidated

Financial Statements. During the six months ended June 30, 2013, we amortized $0.7 million of this discount.

We will have the option to redeem the 2020 Senior Notes, in whole or in part, at any time on or after December 1, 2016, at the specified redemption prices set forth below together with any accrued and unpaid interest, 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, we may redeem all or any part of the 2020 Senior Notes at the "make-whole" redemption price. In addition, prior to December 1, 2015, we may at our option, redeem up to 35% of the aggregate principal amount of the notes at the redemption price of 108% with the net proceeds of a public or private equity offering. We may be required to offer to repurchase the 2020 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. Our and Legacy Reserves Finance Corporation's obligations under the 2020 Senior Notes are guaranteed by our 100% owned subsidiaries Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc. In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the properties of the guarantor; (ii) in connection with any sale or other disposition of sufficient capital stock of the guarantor so that it no longer qualifies as our Restricted Subsidiary (as defined in the indenture); (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance, covenant defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of the guarantor provided no default or event of default has occurred or is occurring; (vi) at such time the guarantor does not have outstanding guarantees of our, or any other guarantor's, other debt; or (vii) upon merging into, or transferring all of its properties to us or another guarantor and ceasing to exist. Refer to Note 11 - Subsidiary Guarantors in the Notes to the Condensed Consolidated Financial Statements for further details on our guarantors.
The indenture governing the 2020 Senior Notes limits our ability and the ability of certain of our subsidiaries to (i) sell assets; (ii) pay distributions on, repurchase or redeem equity interests or purchase or redeem our subordinated debt, provided that such subsidiaries may pay dividends to the holders of their equity interests (including Legacy) and we may pay distributions to the holders of our equity interests subject to the absence of certain defaults, the satisfaction of a fixed charge coverage ratio test and so long as the amount of such distributions does not exceed the sum of available cash (as defined in Legacy's partnership agreement) at Legacy, net proceeds from the sales of certain securities and return of or reductions to capital from restricted investments; (iii) make certain investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from certain of our subsidiaries to Legacy; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in certain transactions with affiliates; (ix) create unrestricted subsidiaries; and (x) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 2020 Senior Notes are rated investment grade by each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indenture) has occurred and is continuing, many of such covenants will terminate and Legacy and our subsidiaries will cease to be subject to such covenants. The indenture also includes customary events of default. Legacy is in compliance with all financial and other covenants of the 2020 Senior Notes.

6.625% Senior Notes Due 2021

On May 28, 2013, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $250 million of our 6.625% Senior Notes due 2021 (the "2021 Senior Notes"). The 2021 Senior Notes were issued at 98.405% of par. Legacy received approximately $240.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by Legacy. During the six months ended June 30, 2013, Legacy amortized $0.04 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 to the date of redemption, if any, 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 or 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 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 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.
Our Revolving Credit Facility

Credit Agreement

On March 10, 2011, we 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"). In conjunction with BNP Paribas' sale of its energy lending practice to Wells Fargo Bank, National Association ("Wells Fargo"), Wells Fargo is now the administrative agent under the Credit Agreement effective April 20, 2012. Our obligations under the Credit Agreement are secured by mortgages on 80% of our oil and natural gas properties as well as a pledge of all of our ownership interests in our operating subsidiaries. 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, which is currently set at $737.5 million with a $2 million sub-limit for letters of credit. The borrowing base is subject to semi-annual redeterminations on or about April 1 and October 1 of each year. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. We also have the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of certain oil and natural gas properties where the purchase price is greater than 10% of the borrowing base. Any increase in the borrowing base requires the consent of all the lenders and any decrease in or maintenance of the borrowing base must be approved by the lenders holding at least 66.67% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility. If the required lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66.67% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility, so long as it does not increase the borrowing base then in effect. Outstanding borrowings in excess of the borrowing base must be prepaid, and, if mortgaged properties represent less than 80% of total value of oil and gas properties evaluated in the most recent reserve report, we must pledge other oil and natural gas properties as additional collateral. Legacy may at any time issue up to $750 million in aggregate principal amount of senior notes or new debt whose proceeds are used to refinance such 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 shall 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 principal amount of the senior notes. After the issuance of the 2020 Senior Notes and the 2021 Senior Notes, we have $200 million of incremental capacity to issue additional senior notes or new debt that remains subject to these provisions. Also, notwithstanding that a lender (or its affiliate) is no longer a party to the Credit Agreement, any lender (or its affiliate) which has entered into any hedging arrangement with us while a party to the Credit Agreement will continue to have our obligations under such hedging arrangement secured on a ratable and pari passu basis by the collateral securing our obligations under the Credit Agreement, the related loan documents and our hedging arrangements.

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

- with respect to ABR loans, the alternate base rate equals the highest of the prime rate, the Federal funds effective rate plus 0.50%, or the one-month London interbank rate ("LIBOR") plus 1.00%, plus an applicable margin ranging from and including 0.75% and 1.75% per annum, determined by the percentage of the borrowing base then in effect that is drawn, or

- with respect to any Eurodollar loans, one-, two-, three- or six-month LIBOR plus an applicable margin ranging from and including 1.75% and 2.75% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

We pay a commitment fee equal to 0.50% per annum on the average daily amount of the unused amount of the commitments under the Credit Agreement, payable quarterly.

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

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

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

Our 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 ASC 815, which includes the current portion of oil, natural gas derivatives and interest rate swaps.

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

- failure to pay any principal when due or any reimbursement amount, interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants or conditions contained in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $2.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or any of our subsidiaries;
- the loan documents cease to be in full force and effect;
- our failing to create a valid lien, except in limited circumstances;
- a change of control, which will occur upon (i) the acquisition by any person or group of persons of beneficial ownership of more than 35% of the aggregate ordinary voting power of our equity securities, (ii) the first day on which a majority of the members of the board of directors of our general partner are not continuing directors (which is generally defined to mean members of our board of directors as of March 10, 2011 and persons who are nominated for election or elected to our general partner's board of directors with the approval of a majority of the continuing directors who were members of such board of directors at the time of such nomination or election), (iii) the direct or indirect sale, transfer or other disposition in one or a series of related transactions of all or substantially all of the properties or assets (including equity interests of subsidiaries) of us and our subsidiaries to any person, (iv) the adoption of a plan related to our liquidation or dissolution or (v) Legacy Reserves GP, LLC ceasing to be our sole general partner;
- the entry of, and failure to pay, one or more adverse judgments in excess of $2.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and
- specified ERISA events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.0 million in any year.

As of June 30, 2013, Legacy was in compliance with all covenants of the revolving credit facility.

Legacy periodically enters into interest rate swap transactions to mitigate the volatility of interest rates. As of June 30, 2013, Legacy had interest rate swaps on notional amounts of $304 million with a weighted-average fixed rate of 2.08%. These swaps mature between October 2013 and November 2015.

Off-Balance Sheet Arrangements

None.

Critical Accounting Policies and Estimates

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

As of June 30, 2013, our critical accounting policies were consistent with those discussed in our Annual Report on Form 10-K for the period ended December 31, 2012.

Use of Estimates

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

Item 3. Quantitative and Qualitative Disclosure About Market Risk.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. These derivative instruments are discussed in Item 1. Financial Statements – Notes to Consolidated Financial Statements – Note 7 Derivative Financial Instruments.

Commodity Price Risk

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

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

As of June 30, 2013, the fair market value of Legacy's commodity derivative positions was a net asset of $35.2 million based on NYMEX futures prices from July 2013 to December 2018 for both oil and natural gas. As of December 31, 2012, the fair market value of Legacy's commodity derivative positions was a net asset of $24.1 million based on NYMEX futures prices from January 2013 to December 2017 for both oil and natural gas. For more discussion about our derivative transactions and to see a table listing the oil and natural gas derivatives from July 2013 through December 2018, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations— Investing Activities."

Interest Rate Risks

At June 30, 2013, Legacy had debt outstanding under its revolving credit facility of $323 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by Legacy under its revolving credit facility for the six-month period ended June 30, 2013 was 2.9%. A 1% increase in LIBOR on Legacy outstanding debt under its revolving credit facility as of June 30, 2013 would result in an estimated

$0.19 million increase in annual interest expense as Legacy has entered into interest rate swaps with a weighted-average fixed rate of 2.08% to mitigate the volatility of interest rates on notional amounts of $304 million of floating rate debt.

Item 4. Controls and Procedures.

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, or the “Exchange Act”) that are designed to ensure that information required to be disclosed in Exchange Act reports is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our general partner’s chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

Our management, with the participation of our general partner’s chief executive officer and chief financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of June 30, 2013. Based upon that evaluation and subject to the foregoing, our general partner’s chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

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

There have been no changes in our internal control over financial reporting that occurred during our fiscal quarter ended June 30, 2013, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, except as discussed in Note 5 to the Condensed Consolidated Financial Statements, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Item 1A. Risk Factors.

In addition to the information set forth in this report, you should carefully consider the factors discussed under "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2012, which could materially affect our business, financial condition or future results. The risks described in these reports are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

Purchases of Equity Securities

	(a)	(b)	(c)	(d)
Period	Total number of units purchased(1)	Price paid per unit	Total number of units purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value of units) that may yet be purchased under the plans or programs
May 17, 2013	4,557	—	—	—

(1) These units were purchased by the Partnership in satisfaction of certain employees' tax withholding obligations.

Item 6. Exhibits.

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.1)
3.2	Amended and Restated Limited Partnership Agreement of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, included as Appendix A to the Prospectus and including specimen unit certificate for the units)
3.3	Amendment No.1, dated December 27, 2007, to the Amended and Restated Agreement of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s Current Report on Form 8-K (File No. 001-33249) filed January 2, 2008, Exhibit 3.1)
3.4	Certificate of Formation of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.3)
3.5	Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)
3.6	First Amendment to Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's Quarterly Report on Form 10-Q (File No. 001-33249) filed May 4, 2012, Exhibit 3.6)
3.7	Second Amendment to Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's Quarterly Report on Form 10-Q (File No. 001-33249) filed May 4, 2012, Exhibit 3.7)
4.1	Indenture, dated as of May 28, 2013, among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (including form of the 6.625% Senior Notes due 2021) (Incorporated by reference to Legacy's Current Report on Form 8-K (File No. 001-33249) filed May 31, 2013, Exhibit 4.1)
4.2	Registration Rights Agreement, dated as of May 28, 2013, by and among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, LLC, UBS Securities LLC, Barclays Capital Inc., Citigroup Global Markets Inc. and J.P. Morgan Securities LLC as representatives of the Initial Purchasers named therein. (Incorporated by reference to Legacy's Current Report on Form 8-K (File No. 001-33249) filed May 31, 2013, Exhibit 4.2)
10.1*	Fifth Amendment to Second Amended and Restated Credit Agreement, dated March 10, 2011, by and between Legacy Reserves LP, Wells Fargo Bank, National Association, as administrative agent, and certain other financial institutions parties thereto as Lenders.
31.1*	Rule 13a-14(a) Certifications (under Section 302 of the Sarbanes-Oxley Act of 2002)
31.2*	Rule 13a-14(a) Certifications (under Section 302 of the Sarbanes-Oxley Act of 2002)
32.1*	Section 1350 Certifications (under Section 906 of the Sarbanes-Oxley Act of 2002)
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.DEF**	XBRL Taxonomy Extenstion Definition Linkbase Document
101.PRE**	XBRL Taxonomy Extenstion Presentation Linkbase Document
101.CAL**	XBRL Taxonomy Extenstion Calculation Linkbase Document
101.LAB**	XBRL Taxonomy Extenstion Label Linkbase Document

* Filed herewith

** Filed electronically herewith.

Pursuant to Rule 406T of Regulation S-T, the interactive data files ("XBRL") on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections. The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed."

SIGNATURES

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

LEGACY RESERVES LP

By: Legacy Reserves GP, LLC, its General Partner

August 7, 2013

By: /s/ James Daniel Westcott
James Daniel Westcott
Executive Vice President and Chief Financial Officer
(On behalf of the Registrant and as Principal Financial Officer)