LEGACY RESERVES LP
Form 10-Q
November 05, 2010

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

FORM 10-Q

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

SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2010

or

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

SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-33249

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

Delaware (State or other jurisdiction of incorporation or organization)	16-1751069 (I.R.S. Employer Identification No.)
303 W. Wall, 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).

£ 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 o	Accelerated filer x
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

40,162,479 units representing limited partner interests in the registrant were outstanding as of November 4, 2010.

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GLOSSARY OF TERMS

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

Bcf. Billion cubic feet.

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

Boe/d. Barrels of oil equivalent per day.

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

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

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

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

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

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

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

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

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.

MMGal. One million gallons of natural gas liquids or other liquid hydrocarbons.

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

NGLs 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, condensate and natural gas liquids.

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

Proved reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

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

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

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 prices as of the period end date and costs over the prior period for periods prior to 2009 and the average annual prices based on the un-weighted arithmetic average of the first-day-of-the-month price for each month of periods beginning on or after December 31, 2009) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Because we are a limited partnership that allocates our taxable income to our unitholders, no provisions for federal or state income taxes have been provided for in the calculation of standardized measure. Standardized measure does not give effect to derivative transactions.

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

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

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

Part I – FINANCIAL INFORMATION

Item 1. Financial Statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

ASSETS

	September 30, 2010	December 31, 2009
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 5,120	$ 4,217
Accounts receivable, net:		
Oil and natural gas	21,524	18,070
Joint interest owners	6,709	4,547
Other	208	364
Fair value of derivatives (Notes 6 and 7)	20,770	20,090
Prepaid expenses and other current assets	2,848	2,323
Total current assets	57,179	49,611
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties, at cost, using the successful efforts method of accounting	1,037,900	847,120
Unproved properties	7,261	214
Accumulated depletion, depreciation and amortization	(326,172)	(271,909)
	718,989	575,425
Other property and equipment, net of accumulated depreciation and amortization of $2,118 and $1,448, respectively	2,645	1,512
Deposits on pending acquisitions	163	6,500
Operating rights, net of amortization of $2,391 and $1,979, respectively	4,626	5,038
Fair value of derivatives (Notes 6 and 7)	9,192	11,026
Other assets, net of amortization of $4,283 and $2,785, respectively	3,755	4,334
Investment in equity method investee	118	47
Total assets	$ 796,667	$ 653,493

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

LIABILITIES AND UNITHOLDERS' EQUITY

	September 30, 2010	December 31, 2009
	(In thousands)	
Current liabilities:		
Accounts payable	$ 3,495	$ 1,580
Accrued oil and natural gas liabilities	26,390	13,890
Fair value of derivatives (Notes 6 and 7)	9,958	18,762
Asset retirement obligation (Note 8)	15,241	13,506
Other (Note 10)	7,586	6,488
Total current liabilities	62,670	54,226
Long-term debt (Note 2)	290,000	237,000
Asset retirement obligation (Note 8)	79,809	71,411
Fair value of derivatives (Notes 6 and 7)	15,620	12,149
Other long-term liabilities	1,065	47
Total liabilities	449,164	374,833
Commitments and contingencies (Note 5)		
Unitholders' equity:		
Limited partners' equity - 40,078,776 and 34,880,474 units issued		
and outstanding at September 30, 2010 and December 31 2009, respectively	347,428	278,627
General partner's equity (approximately 0.1%)	75	33
Total unitholders' equity	347,503	278,660
Total liabilities and unitholders' equity	$ 796,667	$ 653,493

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$42,620	$28,637	$121,998	$69,706
Natural gas liquids sales (NGL)	2,956	3,367	10,138	7,914
Natural gas sales	7,198	5,894	21,936	15,192
Total revenues	52,774	37,898	154,072	92,812
Expenses:				
Oil and natural gas production	16,585	12,517	49,447	35,988
Production and other taxes	3,096	2,251	8,969	5,491
General and administrative	4,536	4,001	13,344	11,269
Depletion, depreciation, amortization and accretion	16,175	13,302	45,356	43,472
Impairment of long-lived assets	4,173	2,375	12,560	3,982
Loss on disposal of assets	453	26	311	265
Total expenses	45,018	34,472	129,987	100,467
Operating income (loss)	7,756	3,426	24,085	(7,655)
Other income (expense):				
Interest income	3	3	10	9
Interest expense (Notes 2, 6 and 7)	(8,215)	(8,612)	(24,553)	(11,110)
Equity in income of partnership	22	16	71	13
Realized and unrealized net gains (losses) on commodity derivatives (Notes 6 and 7)	(19,819)	4,452	30,339	(35,214)
Other	(15)	(1)	73	9
Income (loss) before income taxes	(20,268)	(716)	30,025	(53,948)
Income tax (expense) benefit	83	(135)	(544)	(406)
Net income (loss)	$(20,185)	$(851)	$29,481	$(54,354)
Income (loss) per unit - basic and diluted (Note 9)	$(0.50)	$(0.03)	$0.74	$(1.74)
Weighted average number of units used in computing net income (loss) per unit - basic and diluted	40,079	31,613	39,792	31,247

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2010
(UNAUDITED)

	Number of Limited Partner Units	Limited Partner	General Partner	Total Unitholders' Equity
		(In thousands)		
Balance, December 31, 2009	34,880	$278,627	$33	$278,660
Units issued to Legacy Board of Directors for services	11	226	-	226
Compensation expense on restricted unit awards issued to employees	-	347	-	347
Vesting of restricted units	3	-	-	-
Net proceeds from equity offering	4,888	95,429	-	95,429
Units issued in exchange for oil and natural gas properties	297	5,959	-	5,959
Net distributions to unitholders, $1.56 per unit	-	(62,628)	29	(62,599)
Net income	-	29,468	13	29,481
Balance, September 30, 2010	40,079	$347,428	$75	$347,503

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30, 2010	2009
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ 29,481	$ (54,354)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	45,356	43,472
Amortization of debt issuance costs	1,498	1,178
Impairment of long-lived assets	12,560	3,982
(Gain) loss on derivatives	(19,495)	33,446
Equity in income of partnership	(71)	(13)
Unit-based compensation	1,242	1,836
Loss on disposal of assets	311	265
Changes in assets and liabilities:		
Increase in accounts receivable, oil and natural gas	(3,454)	(3,698)
(Increase) decrease in accounts receivable, joint interest owners	(2,162)	3,136
(Increase) decrease in accounts receivable, other	156	49
(Increase) decrease in other current assets	(517)	1,583
Increase (decrease) in accounts payable	1,915	(4,374)
Increase (decrease) in accrued oil and natural gas liabilities	12,500	(1,148)
Decrease in other liabilities	(442)	(5,561)
Total adjustments	49,397	74,153
Net cash provided by operating activities	78,878	19,799
Cash flows from investing activities:		
Investment in oil and natural gas properties	(182,725)	(16,253)
Decrease in deposit on pending acquisition	6,337	-
Proceeds from sale of assets	-	51
Investment in other equipment	(1,803)	(212)
Goodwill	(494)	-
Net cash settlements on commodity derivatives	15,315	45,760
Investment in equity method investee	-	(5)
Net cash provided by (used in) investing activities	(163,370)	29,341
Cash flows from financing activities:		
Proceeds from long-term debt	231,000	31,000
Payments of long-term debt	(178,000)	(83,000)
Payments of debt issuance costs	(433)	(4,546)
Proceeds from issuance of units, net	95,429	57,269
Distributions to unitholders	(62,599)	(48,476)
Net cash provided by (used in) financing activities	85,397	(47,753)
Net increase in cash and cash equivalents	905	1,387
Cash and cash equivalents, beginning of period	4,217	2,500
Cash and cash equivalents, end of period	$ 5,122	$ 3,887

Non-Cash Investing and Financing Activities:				
Asset retirement obligation costs and liabilities	$	363	$	-
Asset retirement obligations associated with property acquisitions	$	8,780	$	3,025
Units issued in exchange for oil and natural gas properties		5,959		-

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.

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, 2009.

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 less than a 0.1% 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 662/3 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 of West Texas and Southeast New Mexico and the Mid-continent and Rocky Mountain regions of the United States. Legacy has acquired oil and natural gas producing properties and undrilled leaseholds.

The accompanying condensed consolidated financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred. These condensed consolidated financial statements as of September 30, 2010 and for the three and nine months ended September 30, 2010 and 2009 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 financial statements prepared in accordance with GAAP have been condensed or omitted in these financial statements for and as of the three and nine months ended September 30, 2010 and 2009.

(b) Recently Issued Accounting Pronouncements

In January 2010, the FASB issued authoritative guidance intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels, the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance was effective for Legacy on January 1, 2010, except for the disclosures about purchases, sales, issuances and settlements in the Level 3 reconciliation, which will be effective for interim and annual periods beginning after December 15, 2010. As this guidance provides only disclosure requirements, the adoption of this standard did not impact Legacy's results of operations, cash flows or financial position.

(2) Credit Facility

On March 27, 2009, Legacy entered into a new three-year secured revolving credit facility with BNP Paribas as administrative agent (the “Credit Agreement”). Borrowings under the Credit Agreement mature on April 1, 2012. The Credit Agreement permits borrowings in the lesser amount of (i) the borrowing base, or (ii) $600 million. The borrowing base under the Credit Agreement, initially set at $340 million, was redetermined and increased to $410 million on March 31, 2010. The borrowing base is redetermined every six months and is adjusted based upon changes in the fair market value of Legacy’s oil and natural gas assets. Under the Credit Agreement, interest on debt outstanding is charged based on Legacy’s selection of a LIBOR rate plus 2.25% to 3.0%, or the alternate base rate (“ABR”) which equals the highest of the prime rate, the Federal funds effective rate plus 0.50% or LIBOR plus 1.50%, plus an applicable margin between 0.75% and 1.50%. Further, on March 31, 2010, the Credit Agreement was amended. The amendment provides, among other things, that Legacy may at any time issue up to $250 million in aggregate principal amount of senior notes, subject to specified conditions (including that upon issuance of such senior notes our borrowing base would be reduced by an amount equal to 25% of the stated principal amount of the senior notes, or $62.5 million if $250 million of senior notes are issued). 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 Legacy while a party to the Credit Agreement will continue to have Legacy’s obligations under such hedging arrangement secured on a ratable and pari passu basis by the collateral securing Legacy’s obligations under the Credit Agreement, the related loan documents and our hedging arrangements.

As of September 30, 2010, Legacy had outstanding borrowings of $290 million at a weighted-average interest rate of 3.01%. Legacy had approximately $119.9 million of availability remaining under the Credit Agreement as of September 30, 2010. For the nine month period ended September 30, 2010, Legacy paid in cash $6.3 million of interest expense on the Credit Agreement. Legacy’s revolving credit facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- consolidated net income (loss) in total over the last four quarters plus interest expense, income taxes, depreciation, depletion, amortization and other similar charges excluding unrealized gains and losses under ASC 815 (formerly SFAS 133), minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures (“EBITDA”), to interest expense in total over the last four quarters of not less than 2.5 to 1.0;

- total debt as of the last day of the most recent quarter to EBITDA in total over the last four quarters of not more than 3.75 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 (formerly SFAS No. 133), which includes the current portion of oil, natural gas and interest rate swaps.

Interest expense, as defined in the Credit Agreement, differs from interest expense for GAAP purposes, most notably in that it excludes mark-to-market adjustments for interest rate derivatives. At September 30, 2010, Legacy was in compliance with all aspects of the Credit Agreement.

Long-term debt consists of the following at September 30, 2010 and December 31, 2009:

	September 30, 2010	December 31, 2009

	(In thousands)	
Legacy Facility- due April 2012	$290,000	$237,000

(3) Acquisitions

Wyoming Acquisition

On February 17, 2010, Legacy purchased certain oil and natural gas properties located in Wyoming from a third party for a net cash purchase price of $125 million (the "Wyoming Acquisition"). The purchase price was financed partially by Legacy's January 2010 public offering of units and the remainder with borrowings from the Credit Agreement. The effective date of this purchase was November 1, 2009. The operating results from these Wyoming Acquisition properties have been included from their acquisition on February 17, 2010.

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	$	123,587
Unproved properties		6,143
Total assets		129,730
Future abandonment costs		(4,709)
Fair value of net assets acquired	$	125,021

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the Wyoming Acquisition had occurred on January 1, 2010 and 2009. The pro forma amounts are not necessarily indicative of the results that may be reported in the future:

	Three Months Ended September 30,	Nine Months Ended September 30,	
	2009	2010	2009
	(In thousands)		
Revenues	$45,452	$158,305	$111,865
Net income (loss)	$301	$30,724	$(54,347)
Income (loss) per unit - basic and diluted:	$0.01	$0.77	$(1.74)
Units used in computing income (loss) per unit:			
basic and diluted	31,613	39,792	31,247

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

	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
	(In thousands)	
Revenues	$ 7,420	$ 18,999
Excess revenues over direct operating expenses	$ 4,989	$ 10,784

(4) Related Party Transactions

Cary D. Brown, Chairman and Chief Executive Officer of LRGPLLC, and Kyle A. McGraw, Director and Executive Vice President of Business Development and Land of LRGPLLC, own partnership interests 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 $14,808, without respect to property taxes and insurance. The lease expires in August 2011.

Legacy uses Lynch, Chappell and Alsup for legal services. Alan Brown, brother of Cary D. Brown, is a less than ten percent shareholder in this firm. Legacy paid legal fees to Lynch, Chappell and Alsup of $158,382 and $117,808 for the nine months ended September 30, 2010 and 2009, respectively.

(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 believes the likelihood of such a future event to be remote.

Additionally, 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.

(6) Fair Value Measurements

As defined in 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 basis swaps and NGL derivative swaps, for these derivatives indexed to the West Texas Waha, ANR-Oklahoma and CIG indices, and commodity collars. Although Legacy utilizes third party broker quotes to assess the reasonableness of its prices and valuation techniques, Legacy does not have sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

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

Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy Legacy's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2010:

Fair Value Measurements at September 30, 2010 Using

Significant

Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total Carrying Value as of September 30, 2010
		(In thousands)		
LTIP liability (a)	$-	$(4,084)	$ -	$(4,084)
Oil, NGL and natural gas derivative swaps	-	(4,965)	21,205	16,240
Oil collars	-	-	5,657	5,657
Interest rate swaps	-	(17,513)	-	(17,513)
Total	$-	$(26,562)	$ 26,862	$300

(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.

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

	Significant Unobservable Inputs (Level 3)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands)			
Beginning balance	$24,451	$23,899	$17,791	$28,985
Total gains or (losses)	4,991	(1,118)	15,837	1,241
Settlements	(2,580)	(3,208)	(6,766)	(10,653)
Ending balance	$26,862	$19,573	$26,862	$19,573
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of September 30, 2010 and 2009	$2,411	$(4,326)	$9,071	$(9,412)

Fair Value on a Non-Recurring Basis

On January 1, 2009, Legacy adopted 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, the adoption applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value; impaired oil and natural gas property assessments; and the initial recognition of asset retirement obligations for which fair value is used.

The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, Legacy has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of Legacy's asset retirement obligation is presented in Note 8.

Assets measured at fair value during the nine-month period ended September 30, 2010 include:

	Fair Value Measurements at September 30, 2010 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 September 30, 2010
		(In thousands)		
Assets:				
Proved oil and natural gas properties - Impairment (a)			$ 9,225	$9,225
Proved oil and natural gas properties - Acquisitions (b)	$-	$-	$ 169,394	$169,394
Total	$-	$-	$ 178,619	$178,619

(a) Legacy utilizes ASC 360-10-35 to periodically review oil and natural gas properties for impairment when facts and circumstances indicate that their carrying value may not be recoverable. Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. These future price scenarios reflect Legacy's estimation of future price volatility. During the nine-month period ended September 30, 2010, Legacy incurred impairment charges of $12.6 million as oil and natural gas properties with a net cost basis of $21.8 million were written down to their fair value of $9.2 million. The inputs used by management for the fair value measurements utilized in this review include significant unobservable inputs, and therefore, the fair value measurements employed are classified as Level 3 for these types of assets.

(b) Legacy utilizes ASC 805-10 to identify and record the fair value of assets and liabilities acquired in a business combination. During the nine-month period ended September 30, 2010, Legacy acquired oil and natural gas properties with a fair value of $169.4 million in the Wyoming Acquisition and 18 individually immaterial transactions. 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.

(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 price 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.

All of these price risk management transactions are considered derivative instruments and are accounted for in accordance with 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 with changes in fair value being recorded in earnings for the three and nine months ended September 30, 2010 and 2009.

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 nine months ended September 30, 2010 and 2009, Legacy recognized realized and unrealized gains and losses related to its oil, NGL and natural gas derivative transactions. The net gain (loss) from derivative activities was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands)			
Crude oil derivative contract settlements	$3,581	$6,386	$7,772	$33,981
Natural gas liquid derivative contract settlements	-	77	(39)	749
Natural gas derivative contract settlements	2,763	3,663	7,582	11,030
Total commodity derivative contract settlements	6,344	10,126	15,315	45,760
Unrealized change in fair value - oil contracts	(30,074)	(540)	5,137	(76,449)
Unrealized change in fair value - natural gas liquid contracts	-	(130)	39	(1,255)
Unrealized change in fair value - natural gas contracts	3,911	(5,004)	9,848	(3,270)
Total unrealized change in fair value of commodity derivative contracts	(26,163)	(5,674)	15,024	(80,974)
Total realized and unrealized gain (loss) on commodity derivative contracts	$(19,819)	$4,452	$30,339	$(35,214)

As of September 30, 2010, Legacy had the following NYMEX West Texas Intermediate 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
October - December 2010	500,959	$82.21	$60.15 - $140.00
2011	1,625,812	$86.99	$67.33 - $140.00
2012	1,324,466	$82.01	$67.72 - $109.20
2013	881,445	$83.62	$80.10 - $89.35
2014	356,710	$87.88	$87.50 - $90.50

On June 24, 2008, Legacy entered into a NYMEX West Texas Intermediate crude oil derivative collar contract that combines a put option or “floor” with a call option or “ceiling.” The following table summarizes the contract as of September 30, 2010:

Calendar Year	Volumes (Bbls)	Floor Price	Ceiling Price
October - December 2010	18,100	$120.00	$156.30
2011	68,300	$120.00	$156.30
2012	65,100	$120.00	$156.30

On May 3, 2010, Legacy entered into two separate NYMEX West Texas Intermediate crude oil derivative three-way collar contracts. Each contract combines a long and short put with a short call. The following table summarizes the three-way oil collar contracts as of September 30, 2010:

Calendar Year	Volumes (Bbls)	Short Put	Long Put	Short Call
July 2013 - June 2014	65,700	$60.00	$85.00	$124.00
July 2014 - June 2015	146,000	$60.00	$85.00	$130.05

As of September 30, 2010, Legacy had the following NYMEX Henry Hub, ANR-OK, CIG and Waha 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
October - December 2010	983,094	$7.18	$5.33 - $8.88
2011	3,038,316	$7.49	$5.74 - $8.70
2012	2,357,990	$7.49	$5.72 - $8.70
2013	1,402,754	$6.58	$5.78 - $6.89
2014	609,104	$6.36	$5.95 - $6.47

As of September 30, 2010, Legacy had the following gas basis swaps in which it receives floating NYMEX prices less a fixed basis differential and pay prices on the floating Waha index, a natural gas hub in West Texas. The prices that Legacy receives for its natural gas sales in the Permian Basin follow Waha more closely than NYMEX:

Annual Basis Differential

Calendar Year	Volumes (MMBtu)	per MMBtu
October - December 2010	300,000	($0.57)

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.

On August 29, 2007, Legacy entered into LIBOR interest rate swaps beginning in October of 2007 and extending through November 2011. On January 29, 2009, Legacy revised the LIBOR interest rate swaps. The revised swap transaction has Legacy paying its counterparty fixed rates ranging from 4.09% to 4.11%, per annum, and receiving floating rates on a total notional amount of $54 million. The swaps are settled on a monthly basis, beginning in January of 2009 and ending in November of 2013.

On March 14, 2008, Legacy entered into a LIBOR interest rate swap beginning in April of 2008 and extending through April of 2011. On January 28, 2009, Legacy revised the LIBOR interest rate swap extending the term through April of 2013. The revised swap transaction has Legacy paying its counterparty a fixed rate of 2.65% per annum, and receiving floating rates on a notional amount of $60 million. The swap is settled on a monthly basis, beginning in April of 2009 and ending in April of 2013. Prior to April of 2009, the swap was settled on a quarterly basis.

On October 6, 2008, Legacy entered into two LIBOR interest rate swaps beginning in October of 2008 and extending through October 2011. In January of 2009, Legacy revised these LIBOR interest rate swaps extending the termination date through October of 2013. The revised swap transactions have Legacy paying its counterparties fixed rates ranging from 3.09% to 3.10%, per annum, and receiving floating rates on a total notional amount of $100 million. The revised swaps are settled on a monthly basis, beginning in January of 2009 and ending in October of 2013.

On December 16, 2008, Legacy entered into a LIBOR interest rate swap beginning in December of 2008 and extending through December 2013. The swap transaction has Legacy paying its counterparty a fixed rate of 2.295%, per annum, and receiving floating rates on a total notional amount of $50 million. The swap is settled on a quarterly basis, beginning in March of 2009 and ending in December of 2013.

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.

As the term of Legacy’s interest rate swaps extends through December of 2013, a period that extends beyond the term of the Credit Agreement, which expires on April 1, 2012, Legacy did 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 an increase/(reduction) of interest expense. The total impact on interest expense from the mark-to-market and settlements was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands)			

Interest rate swap settlements	$1,812	$1,933	$5,547	$3,812
Unrealized change in fair value - interest rate swaps	3,383	3,644	10,844	(1,768)
Total increase to interest expense, net	$5,195	$5,577	$16,391	$2,044

The table below summarizes the interest rate swap position as of September 30, 2010.

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at September 30, 2010
		(Dollars in thousands)		
$ 29,000	4.090 %	10/16/2007	10/16/2013	$ (2,893)
$ 13,000	4.110 %	11/16/2007	11/16/2013	(1,330)
$ 12,000	4.110 %	11/28/2007	11/28/2013	(1,221)
$ 60,000	2.650 %	4/1/2008	4/1/2013	(2,918)
$ 50,000	3.100 %	10/10/2008	10/10/2013	(3,469)
$ 50,000	3.090 %	10/10/2008	10/10/2013	(3,453)
$ 50,000	2.295 %	12/18/2008	12/18/2013	(2,229)
Total Fair Market Value of interest rate derivatives				$ (17,513)

(8) Asset Retirement Obligation

ASC 410-20 requires that an asset retirement obligation ("ARO") associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which it is incurred and becomes determinable. Under this method, when liabilities for dismantlement and abandonment costs, excluding salvage values, are initially recorded, the carrying amount of the related oil and natural gas properties is increased. The fair value of the ARO asset and liability is measured using expected future cash outflows discounted at Legacy's credit-adjusted risk-free interest rate. Accretion of the liability is recognized each period using the interest method of allocation, and the capitalized cost is depleted over the useful life of the related asset.

The following table reflects the changes in the ARO during the nine months ended September 30, 2010 and year ended December 31, 2009.

	September 30, 2010	December 31, 2009
	(In thousands)	
Asset retirement obligation - beginning of period	$84,917	$80,424
Liabilities incurred with properties acquired	8,780	3,505
Liabilities incurred with properties drilled	-	182
Liabilities settled during the period	(1,581)	(2,255)
Current period accretion	2,571	3,061
Current period revisions to previous estimates	363	-
Asset retirement obligation - end of period	$95,050	$84,917

(9) Earnings Per Unit

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands)			
Income (loss) available to unitholders	$(20,185)	$(851)	$29,481	$(54,354)
Weighted average number of units outstanding	40,079	31,613	39,792	31,247
Effect of dilutive securities:				
Restricted units	-	-	-	-
Weighted average units and potential units outstanding	40,079	31,613	39,792	31,247
Basic and diluted earnings (loss) per unit	$(0.50)	$(0.03)	$0.74	$(1.74)

For the three and nine months ended September 30, 2010, 83,703 restricted units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect. For the three and nine months ended September 30, 2009, 5,000 restricted units were excluded from the calculation of diluted earnings per share due to their anti-dilutive effect.

(10) Unit-Based Compensation

Long-Term Incentive Plan

On March 15, 2006, a Long-Term Incentive Plan (the “LTIP”) for Legacy was put in place and Legacy adopted ASC 718. Legacy adopted the LTIP 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. The LTIP permits the grant of awards covering an aggregate of 2,000,000 units. As of September 30, 2010 grants of awards net of forfeitures covering 1,359,415 units had been made, comprised of 266,014 unit option awards, 644,301 unit appreciation rights awards, 146,319 restricted unit awards, 246,738 phantom unit awards and 56,043 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. Prior to April 2007, Legacy utilized the equity method of accounting as described in ASC 718 to recognize the cost associated with unit options. 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.”

The initial vesting of options occurred on March 15, 2007, with initial option exercises occurring in April 2007. At the time of the initial exercise, Legacy settled these exercises in cash and determined it was likely to do so for future option exercises. Consequently, in April 2007, Legacy began accounting for unit option and unit appreciation rights (“UARs”) 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 the period. Compensation cost is recognized based on the change in the liability between periods.

Unit Options and Unit Appreciation Rights

During the year ended December 31, 2009, Legacy issued 9,500 UARs to employees which vest ratably over a three-year period and 116,951 UARs to employees which vest at the end of a three-year period. During the nine-month period ended September 30, 2010, Legacy issued 63,500 UARs to employees which vest ratably over a three-year period and 116,951 UARs to employees which vest at the end of a three-year period. UARs granted prior to August 20, 2009 expire five years from the grant date and are exercisable when they vest. Those UARs granted on or after August 20, 2009 expire seven years from the grant date and are exercisable when they vest.

For the nine-month periods ended September 30, 2010 and 2009, Legacy recorded $1,211,151 and $1,099,018, respectively, of compensation expense due to the change in liability from December 31, 2009 and 2008, respectively, based on its use of the Black-Scholes model to estimate the September 30, 2010 and 2009 fair value of these unit options and UARs (see Note 6). For the three-month periods ended September 30, 2010 and 2009, Legacy recorded $460,477 and $950,955, respectively, of compensation expense due to the changes in liability from June 30, 2010 and 2009, based on its use of the Black-Scholes model to estimate the September 30, 2010 and 2009 fair value of these options and UARs. As of September 30, 2010, there was a total of approximately $1.6 million of unrecognized compensation costs related to the unexercised and non-vested portion of these unit options and UARs. At September 30, 2010, 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 September 30, 2010 and is recognized as a percentage of the service period satisfied. Since Legacy has limited trading history, it has used an estimated volatility factor of approximately 55% based upon the historical trends of a representative group of publicly-traded companies in the energy industry and employed the Black-Scholes model to estimate the September 30, 2010 fair value to be realized as compensation cost based on the percentage of service period satisfied. In the absence of historical data, Legacy has assumed an estimated forfeiture rate of 5%. As required by ASC 718, Legacy will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.08 per unit.

A summary of option and UAR activity for the nine months ended September 30, 2010 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2010	700,829			
Granted	180,451	$23.76		
Exercised	(235,794)	$17.23		
Forfeited	-	$-		
Outstanding at September 30, 2010	645,486	$21.22	4.25	$2,394,197
Options and UARs exercisable at September 30, 2010	199,639	$22.90	2.00	$525,252

The following table summarizes the status of Legacy's non-vested unit options and UARs since January 1, 2010:

	Non-Vested Options and UARs	
	Number of Units	Weighted-Average Exercise Price
Non-vested at January 1, 2010	389,378	$19.20
Granted	180,451	23.76
Vested - Unexercised	(110,163)	21.65
Vested - Exercised	(13,819)	18.39
Forfeited	-	-
Non-vested at September 30, 2010	445,847	$20.47

Legacy has used a weighted-average risk-free interest rate of 1.1% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at September 30, 2010 whose term is consistent with the expected life of the unit options and UARs. Expected life represents the period of time that options and UARs are expected to be outstanding and is based on Legacy's best estimate. The following table represents the weighted-average assumptions used for the Black-Scholes option-pricing model.

	Nine Months Ended September 30, 2010
Expected life (years)	4.25
Annual interest rate	1.1 %
Annual distribution rate per unit	$2.08
Volatility	55 %

Restricted and Phantom Units

As described below, Legacy has also issued phantom units under the LTIP. A phantom unit is a notional unit that entitles the holder, upon vesting, to receive 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 awards in cash, Legacy is accounting for the phantom units by utilizing the liability method.

On January 29, 2009, Legacy granted 4,500 phantom units to six employees which vest ratably over a three-year period, beginning at the date of grant. On May 31, 2010, Legacy granted 10,000 phantom units to an employee which vest ratably over a five-year period, beginning at the date of grant. On June 7, 2010, Legacy granted 15,000 phantom units to an employee which vest ratably over a five-year period, beginning at the date of grant. In conjunction with these grants, the employees are entitled to distribution equivalent rights ("DERs") for unvested units held at the date of dividend payment.

On August 20, 2007, the board of directors of Legacy's general partner, upon the recommendation of the Compensation Committee, approved phantom unit awards of up to 175,000 units to five key executives of Legacy based on achievement of targeted annualized per unit distribution levels over a base amount of $1.64 per unit. These awards are to be determined annually based solely on the annualized level of per unit distributions for the fourth quarter of each calendar year and subsequently vest over a three-year period. There is a range of 0% to 100% of the distribution levels at which the performance condition may be met. For each quarter, management recommends to the board an appropriate level of per unit distribution based on available cash of Legacy. The level of distribution is set by the board subsequent to management's recommendation. Probable issuances for the purposes of calculating compensation expense associated therewith are determined based on management's determination of probable future distribution levels. Expense associated with probable vesting is recognized over the period from the date probable vesting is determined to the end of the three-year vesting period. On February 4, 2008, the Compensation Committee approved the award of 28,000 phantom units to Legacy's five executive officers. On January 29, 2009, the Compensation Committee approved the award of 49,000 phantom units to Legacy's five executive officers. In conjunction with these grants, the executive officers are entitled to DERs for unvested units held at the date of dividend payment.

On September 21, 2009, the board of directors of Legacy's general partner, upon the recommendation of the Compensation Committee, implemented changes to the equity-based incentive compensation policy applicable to the five executive officers of Legacy. The new compensation policy replaced the compensation policy implemented on August 17, 2007. Un-vested phantom unit awards previously granted under the prior compensation policy remain outstanding. In addition to cash bonus awards, under the new 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 ranging from 40% to 100% 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 ranging from 60% to 150%, 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 ordinal 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. The percentage of the 50% performance-based award to vest under this step is determined within a matrix which ranges from 0% to 100% and will increase from 0% to 100% as each of the Legacy TUR and the ordinal rank of the Legacy TUR among the peer group increase. The applicable Legacy TUR range is from less than 8% (where no vesting will occur) to more than 20% (where 100% of the amount available under this step is subject to vesting, dependent upon the Legacy TUR rank among the peer group). 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 percentage of the 50% of the performance-based award to vest under this step is determined within a matrix which ranges from 0% to 100% and will increase from 0% to 100% as the Legacy TUR and the percentile rank of the Legacy TUR among the Alerian MLP Index increases. The applicable Legacy TUR range is from less than 8% (where no vesting will occur) to more than 20% (where 100% of the amount available under this step is subject to vesting, dependent upon the Legacy TUR rank among 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, DERs will accumulate and accrue based on the total number of actual amounts vested and will be payable at the date of vesting.

On February 18, 2010, the Compensation Committee approved the award of 44,869 subjective, or service-based, phantom units and 71,619 objective, or performance based, phantom units to Legacy's five executive officers.

Compensation expense related to the phantom units and associated DERs was $1,503,697 and $675,702 for the nine months ended September 30, 2010 and 2009, respectively. Compensation expense related to the phantom units and associated DERs was $681,425 and $369,007 for the three months ended September 30, 2010 and 2009, respectively.

On March 15, 2006, Legacy issued an aggregate of 52,616 restricted units to two employees. The restricted units awarded vest ratably over a three-year period, beginning on the date of grant. On May 5, 2006, Legacy issued 12,500 restricted units to an employee. The restricted units awarded vest ratably over a five-year period, beginning on March 31, 2007. On April 1, 2010, Legacy issued an aggregate of 81,203 restricted units to nine employees. The restricted units awarded vest ratably over a three-year period, beginning on the date of grant. Compensation expense related to restricted units was $347,213 and $92,335 for the nine months ended September, 30, 2010 and 2009, respectively. Compensation expense related to restricted units was $168,294 and $10,625 for the three months ended September, 30, 2010 and 2009, respectively. As of September 30, 2010, there was a total of $1.6 million of unrecognized compensation expense related to the non-vested portion of these restricted units. At September 30, 2010, this cost was expected to be recognized over a weighted-average period of 2.5 years. Pursuant to the provisions of ASC 718, Legacy's issued units, as reflected in the accompanying consolidated balance sheet at September 30, 2010, do not include 83,703 units related to unvested restricted unit awards.

On August 20, 2009, Legacy granted and issued 3,227 units to each of its five non-employee directors as part of their annual compensation for serving on the board of directors of Legacy's general partner. The value of each unit was $16.07 at the time of issuance. On May 24, 2010, Legacy granted and issued 2,215 units to each of its five non-employee directors as part of their annual compensation for serving on the board of directors of Legacy's general partner. The value of each unit was $20.38 at the time of issuance.

(11) Shelf Registration Statement

During the second quarter of 2008, Legacy filed a registration statement with the SEC which registered securities in an aggregate offering amount of up to $500 million of any combination of debt securities and units. Net proceeds, terms and pricing of the offering of securities issued under the 2008 shelf registration statement are determined at the time of any offering. The filing of the shelf registration statement does not in itself indicate that Legacy will or could sell any such securities. Legacy's ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or units will depend upon, among other things, market conditions and sufficient demand at prices acceptable to Legacy.

In September of 2009, Legacy issued 3,795,000 units in a public offering at an undiscounted price of $15.85 per unit, for gross proceeds of $60.2 million, before underwriting discount and offering costs.

In January of 2010, Legacy issued 4,887,500 units in a public offering at an undiscounted price of $20.42 per unit, for gross proceeds of $99.8 million, before underwriting discount and offering costs.

As a result of these offerings, Legacy has approximately $340 million remaining available for issuance under its 2008 shelf registration statement as of September 30, 2010.

(12) Subsequent Events

On October 6, 2010, Legacy entered into crude oil derivative contracts with four counterparties, all of whom are lenders to Legacy under its Credit Agreement. These contracts are summarized as follows:

Swaps

Calendar Year	Volumes (Bbls)	Price per Bbl
2011 (a)	182,500	$98.25
2011	80,300	$87.00

(a) As part of an oil swap transaction entered into with a counterparty, we sold two call options to the counterparty that allow the counterparty to extend this swap transaction covering calendar year 2011 to either 2012, 2013 or both calendar years. The counterparty must exercise or decline the option covering calendar year 2012 on December 30, 2011 and the option covering calendar year 2013 on December 31, 2012. If exercised, we would pay the counterparty floating prices and receive a fixed price of $98.25 on annual notional volumes of 183,000 Bbls in 2012 and 182,500 Bbls in 2013. The premium paid by the counterparty for the two call options was received by us as an increase in the fixed price that we will receive pursuant to the 2011 swap to $98.25 per Bbl on 182,500 Bbls, or 500 Bbls per day, rather than the prevailing market price of approximately $87.00 per Bbl.

3-Way Collars

Calendar Year	Volumes (Bbls)	Average Short Put	Average Long Put	Average Short Call
2012	73,200	$60.00	$85.00	$99.81
2013	237,250	$60.00	$85.00	$104.65
2014	248,200	$60.00	$85.00	$109.90
2015	259,150	$60.00	$85.00	$115.80

On October 7, 2010, Legacy announced that its bank group has completed its semi-annual redetermination of its borrowing base applicable to its Credit Agreement and maintained its borrowing base at $410 million. The next borrowing base redetermination is scheduled for April 2011.

On October 21, 2010, Legacy's board of directors approved a distribution of $0.52 per unit payable on November 12, 2010 to unitholders of record on November 1, 2010.

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, 2009 and Legacy's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010 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

We were formed in October 2005. Upon completion of our private equity offering on March 15, 2006, we acquired oil and natural gas properties and business operations from our founding investors and three charitable foundations.

Because of our rapid growth through acquisitions and development of properties, historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results. The operating results from the Wyoming Acquisition have been included from February 17, 2010.

Acquisitions have been financed with a combination of proceeds from bank borrowings, 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 utilizing multiple types of recovery techniques such as secondary (waterflood) and tertiary (CO_2) recovery methods to repressure the reservoir and recover additional oil, drilling to find additional reserves, re-stimulating existing wells and acquiring more reserves than we produce. 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 and obtain regulatory approvals.

Our revenues are highly sensitive to changes in oil and natural gas prices and to levels of production. As set forth under “Cash Flow from Operations” below, we have entered into derivative transactions covering a significant portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in oil and natural gas prices will affect our ability to execute our capital investment programs and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in oil and natural gas prices may have on the value of our proved reserves and their impact, 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. Accordingly, we continuously monitor our production and operating costs per well to determine if any wells or properties should be shut-in, recompleted or sold.

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.

Operating Data

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$42,620	$28,637	$121,998	$69,706
Natural gas liquid sales	2,956	3,367	10,138	7,914
Natural gas sales	7,198	5,894	21,936	15,192
Total revenue	$52,774	$37,898	$154,072	$92,812
Expenses:				
Oil and natural gas production	$14,908	$11,462	$45,032	$32,671
Ad valorem taxes	$1,677	$1,055	$4,415	$3,317
Total oil and natural gas production	$16,585	$12,517	$49,447	$35,988
Production and other taxes	$3,096	$2,251	$8,969	$5,491
General and administrative	$4,536	$4,001	$13,344	$11,269
Depletion, depreciation, amortization and accretion	$16,175	$13,302	$45,356	$43,472
Realized commodity derivative settlements				
Realized gain on oil derivatives	$3,581	$6,386	$7,772	$33,981
Realized gain (loss) on natural gas liquid derivatives	$-	$77	$(39)	$749
Realized gain on natural gas derivatives	$2,763	$3,663	$7,582	$11,030
Production:				
Oil - MBbls	607	438	1,692	1,339
Natural gas liquids - Mgals	3,070	4,084	9,781	11,316
Natural gas - MMcf	1,332	1,306	3,798	3,813
Total (MBoe)	902	753	2,558	2,244
Average daily production (Boe/d)	9,804	8,185	9,370	8,220
Average sales price per unit (excluding commodity derivatives):				
Oil price per barrel	$70.21	$65.38	$72.10	$52.06
Natural gas liquid price per gallon	$0.96	$0.82	$1.04	$0.70
Natural gas price per Mcf	$5.40	$4.51	$5.78	$3.98
Combined (per Boe)	$58.51	$50.33	$60.23	$41.36
Average sales price per unit (including realized commodity derivative settlements):				
Oil price per barrel	$76.11	$79.96	$76.70	$77.44
Natural gas liquid price per gallon	$0.96	$0.84	$1.03	$0.77
Natural gas price per Mcf	$7.48	$7.32	$7.77	$6.88
Combined (per Boe)	$65.54	$63.78	$66.22	$61.75
NYMEX oil index prices per barrel:				

Beginning of Period	$75.63	$69.89	$79.36	$44.60
End of Period	$79.97	$70.61	$79.97	$70.61
NYMEX gas index prices per Mcf:				
Beginning of Period	$4.62	$3.84	$5.57	$5.62
End of Period	$3.87	$4.84	$3.87	$4.84
Average unit costs per Boe:				
Oil and natural gas production	$16.53	$15.22	$17.60	$14.56
Ad valorem taxes	$1.86	$1.40	$1.73	$1.48
Production and other taxes	$3.43	$2.99	$3.51	$2.45
General and administrative	$5.03	$5.31	$5.22	$5.02
Depletion, depreciation, amortization and accretion	$17.93	$17.67	$17.73	$19.37

Results of Operations

Three-Month Period Ended September 30, 2010 Compared to Three-Month Period Ended September 30, 2009

Legacy's revenues from the sale of oil were $42.6 million and $28.6 million for the three-month periods ended September 30, 2010 and 2009, respectively. Legacy's revenues from the sale of NGLs were $3.0 million and $3.4 million for the three-month periods ended September 30, 2010 and 2009, respectively. Legacy's revenues from the sale of natural gas were $7.2 million and $5.9 million for the three-month periods ended September 30, 2010 and 2009, respectively. The $14.0 million increase in oil revenues reflects the increase in average realized price of $4.83 per Bbl (7%) as well as an increase in oil production of 169 MBbls (39%) due primarily to Legacy's purchase of additional oil and natural gas properties, including the Wyoming Acquisition. The $0.4 million decrease in proceeds from NGL sales reflects the decrease in NGL production of approximately 1,014 MGals (25%) due primarily to significant plant and gathering system downtime from one of our NGL purchasers in the Texas Panhandle. As our NGL sales are dependent on the availability of processing capacity, lengthy downtimes from third-party plant operators can have a significant adverse impact on our operations. This decrease was partially offset by the $0.14 per gallon (17%) increase in realized NGL price. The $1.3 million increase in natural gas revenues reflects the increase in average realized price of $0.89 per Mcf (20%) as well as an increase in natural gas production of approximately 26 MMcf (2%) due primarily to operational improvements and Legacy's purchase of additional oil and natural gas properties, including the Wyoming Acquisition. These increases in natural gas production were partially offset by production declines due to plant and gathering system downtime from one of our gas purchasers in the Texas Panhandle.

For the three-month period ended September 30, 2010, Legacy recorded $19.8 million of net losses on oil and natural gas derivatives comprised of realized gains of $6.3 million from net cash settlements of oil and natural gas derivative contracts and a net unrealized loss of $26.2 million. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods. Legacy had unrealized net losses from oil derivatives because oil futures prices increased during the three-month period ended September 30, 2010. NYMEX oil futures prices at September 30, 2010 were on average more than the average contract prices of Legacy's outstanding oil derivatives contracts, and the increase in the NYMEX oil futures prices during the quarter resulted in a negative differential between Legacy's outstanding oil derivatives and NYMEX prices. Accordingly, the net asset attributable to unrealized net gains from Legacy's outstanding oil derivatives became a net liability, resulting in an unrealized net loss for the quarter. Legacy had unrealized net gains from natural gas derivatives because the NYMEX natural gas futures prices decreased during the three-month period ended September 30, 2010. Due to this decrease in natural gas prices during the quarter, the positive differential between Legacy's fixed price natural gas derivatives and NYMEX prices increased. Accordingly, the net asset attributable to unrealized net gains from Legacy's outstanding natural gas derivatives increased, resulting in unrealized net gains for the quarter. For the three-month period ended September 30, 2009, Legacy recorded $4.4 million of net gains on oil, NGL and natural gas derivatives, comprised of realized gains of $10.1 million from net cash settlements of oil, NGL and natural gas derivative contracts and net unrealized losses of $5.7 million on oil, NGL and natural gas derivative contracts.

Legacy's oil and natural gas production expenses, excluding ad valorem taxes, increased to $14.9 million ($16.53 per Boe) for the three-month period ended September 30, 2010, from $11.5 million ($15.22 per Boe) for the three-month period ended September 30, 2009. Production expenses increased primarily due to industry-wide cost increases, particularly those directly related to higher commodity prices, such as the cost of electricity, which powers artificial lift equipment and pumps involved in the production of oil. In addition, oil and natural gas production expenses increased due to the purchases of oil and natural gas properties, including approximately $1.5 million of expenses related to the Wyoming Acquisition, which closed on February 17, 2010. The properties acquired in the Wyoming acquisition have historically experienced a higher production expense per Boe than the oil and natural gas properties Legacy owns in the Permian Basin and Texas Panhandle. Legacy's ad valorem tax expense increased to $1.7 million ($1.86 per Boe) for the three-month period ended September 30, 2010, from $1.1 million ($1.40 per Boe) for the three-month period ended September 30, 2009 primarily due to $0.5 million of ad valorem tax expenses related to the Wyoming Acquisition.

Legacy's production and other taxes were $3.1 million and $2.3 million for the three-month periods ended September 30, 2010 and 2009, respectively. Production and other taxes increased primarily because of the increases in realized prices and production volumes, as production and other taxes as a percentage of revenue remained largely unchanged.

Legacy's general and administrative expenses were $4.5 million and $4.0 million for the three-month periods ended September 30, 2010 and 2009, respectively. General and administrative expenses increased primarily due to increased salary expense related to the hiring of additional employees and costs related to an accounting system conversion. These increases were partially offset by a reduction in non-cash LTIP expenses during the period ended September 30, 2010, as LTIP liabilities and corresponding mark-to-market adjustments were reduced due to cash settlements of those liabilities.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $16.2 million and $13.3 million for the three-month periods ended September 30, 2010 and 2009, respectively. DD&A increased primarily because of increased production from recent acquisitions, including the Wyoming Acquisition, and proportionate increases in cost basis, as DD&A expense per Boe of $17.93 for the three-month period ended September 30, 2010 is relatively unchanged from DD&A expense per Boe of $17.67 for the three-month period ended September 30, 2009.

Impairment expense was $4.2 million and $2.4 million for the three-month periods ended September 30, 2010 and 2009, respectively. In the three-month period ended September 30, 2010, Legacy recognized impairment expense on 6 separate producing fields, due primarily to (i) the write-off of multiple PUDs in one field due to the performance of offset locations that no longer supported the economic viability of the PUDs, (ii) the performance decline of a single well in one field that reduced the expected future net revenue below the carrying value of the field and (iii) the expected future net revenues in four separate fields that did not exceed the total cost basis of the fields. Impairment expense for the period ended September 30, 2009, was related to a single producing field due to additional cost basis related to the ARO asset from an acquisition during the period, the recognition of which resulted in the net cost basis exceeding the expected future net revenues of the field.

Legacy recorded interest expense of $8.2 million and $8.6 million for the three-month periods ended September 30, 2010 and 2009, respectively. Interest expense decreased approximately $0.4 million due primarily to declines in our interest rate swap mark-to-market adjustment and related swap settlements.

Nine-Month Period Ended September 30, 2010 Compared to Nine-Month Period Ended September 30, 2009

Legacy's revenues from the sale of oil were $122.0 million and $69.7 million for the nine-month periods ended September 30, 2010 and 2009, respectively. Legacy's revenues from the sale of NGLs were $10.1 million and $7.9 million for the nine-month periods ended September 30, 2010 and 2009, respectively. Legacy's revenues from the sale of natural gas were $21.9 million and $15.2 million for the nine-month periods ended September 30, 2010 and 2009, respectively. The $52.3 million increase in oil revenues reflects the increase in average realized price of $20.04 per Bbl (38%) as well as an increase in oil production of 353 MBbls (26%) due primarily to Legacy's purchase of the oil and natural gas properties, including the Wyoming Acquisition. The $2.2 million increase in proceeds from NGL sales reflects the increase in realized NGL price of $0.34 per gallon (49%) partially offset by a decrease in NGL production of approximately 1,535 MGals (14%) due primarily to significant plant and gathering system downtime from one of our NGL purchasers in the Texas Panhandle. As our NGL sales are dependent on the availability of processing capacity, lengthy downtimes from third-party plant operators can have a significant adverse impact on our operations. The $6.7 million increase in natural gas revenues reflects an increase in average realized price of $1.80 per Mcf (45%) partially offset by a decrease in natural gas production of approximately 15 MMcf (0.4%). This decrease in natural gas production was due primarily to plant and gathering system downtime from one of our gas purchasers in the Texas Panhandle, but was mostly offset by increased production attributable to recent acquisitions, including the Wyoming Acquisition, and operational improvements.

For the nine-month period ended September 30, 2010, Legacy recorded $30.3 million of net gains on oil and natural gas derivatives comprised of realized gains of $15.3 million from net cash settlements of oil, NGL and natural gas derivative contracts and a net unrealized gain of $15.0 million. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods. Even though the spot price of oil increased during the nine-month period ended September 30, 2010, Legacy had unrealized net gains from oil derivatives because oil futures prices decreased during the nine-month period ended September 30, 2010. Average NYMEX futures prices declined from $89.42 for fiscal years 2011 through 2014 at December 31, 2009 compared to an average oil futures price of $87.78 at September, 30. 2010 over the same period. Due to decreases in oil futures prices during the nine months ended September 30, 2010, the negative differential between Legacy's outstanding oil derivatives and NYMEX prices was reduced. Accordingly, the net liability attributable to unrealized losses from Legacy's oil derivatives was reduced, resulting in net unrealized gains for the nine-months ended September 30, 2010. Legacy had unrealized net gains from natural gas derivatives because NYMEX natural gas futures prices decreased during the nine-month period ended September 30, 2010. Due to decreases in natural gas prices, the positive differential between Legacy's natural gas derivatives and NYMEX prices increased. Accordingly, the net asset attributable to unrealized net gains from Legacy's natural gas derivatives increased, resulting in net unrealized gains for the nine-month period ended September 30, 2010. For the nine-month period ended September 30, 2009, Legacy recorded $35.2 million of net losses on oil, NGL and natural gas derivatives comprised of realized gains of $45.8 million from net cash settlements of oil, NGL and natural gas derivative contracts and a net unrealized loss of $81.0 million on oil, NGL and natural gas derivative contracts.

Legacy's oil and natural gas production expenses, excluding ad valorem taxes, increased to $45.0 million ($17.60 per Boe) for the nine-month period ended September 30, 2010, from $32.7 million ($14.56 per Boe) for the nine-month period ended September 30, 2009. Production expenses increased primarily due to industry-wide cost increases, particularly those directly related to higher commodity prices, such as the cost of electricity, which powers artificial lift equipment and pumps involved in the production of oil. In addition, oil and natural gas production expenses increased due to recent acquisitions, including approximately $5.9 million of expenses related to the Wyoming Acquisition, which closed on February 17, 2010. The properties acquired in the Wyoming acquisition have historically experienced a higher production expense per Boe than the oil and gas properties we own in the Permian Basin and Texas Panhandle. In addition, the Wyoming expenses described above include approximately $0.6 million in workovers, as well as other maintenance-related production expenses, that were necessary to improve or re-establish production in several underperforming and offline wells. Legacy's ad valorem tax expense increased to $4.4 million ($1.73 per Boe) for the nine-month period ended September 30, 2010, from $3.3 million ($1.48 per Boe) for the nine-month period ended September 30, 2009 primarily due to ad valorem taxes related to recent acquisitions, including the Wyoming acquisition.

Legacy's production and other taxes were $9.0 million and $5.5 million for the nine-month periods ended September 30, 2010 and 2009, respectively. Production and other taxes increased primarily because of increases in realized prices and production volumes, as production and other taxes as a percent of revenue remained largely unchanged.

Legacy's general and administrative expenses were $13.3 million and $11.3 million for the nine-month periods ended September 30, 2010 and 2009, respectively. General and administrative expenses increased approximately $2.0 million between the nine-month periods ended September 30, 2010 and 2009 primarily due to increases in non-cash LTIP expenses of $1.2 million due to increased grant amounts and rising unit prices as well as an increase in salary expense related to the hiring of additional employees. As the LTIP is tied to our unit performance, rising unit prices result in an increase in LTIP expenses whereas our unit prices decreased during the nine-month period ended September 30, 2009, resulting in lower expenses during that period.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $45.4 million and $43.5 million for the nine-month periods ended September 30, 2010 and 2009, respectively. DD&A increased primarily because of increased production from recent acquisitions, including the Wyoming Acquisition, and overall increases in cost basis related. DD&A expense per Boe declined to $17.73 per Boe for the nine-month period ended September 30, 2010 from $19.37 per Boe for the nine-month period ended September 30, 2009 due primarily to increases in reserves largely resulting from increased commodity prices.

Impairment expense was $12.6 million and $4.0 million for the nine-month periods ended September 30, 2010 and 2009, respectively. In the nine-month period ended September 30, 2010, Legacy recognized impairment expense on 60 separate producing fields, due primarily to (i) the decrease in oil and natural gas prices and increased lifting costs experienced during the second quarter of 2010, which decreased the expected future net revenue below the carrying value of the assets, (ii) the write-off of multiple PUDs in one field due to the performance of offset locations that no longer supported the economic viability of the PUDs and (iii) the performance decline of a single well in one field that reduced the expected future net revenue below the carrying value of the field. Impairment expense for the period ended September 30, 2009, was related to seven separate producing fields due primarily to lower natural gas prices, increased cost basis on an acquired field and, in the case of one field, performance.

Legacy recorded interest expense of $24.5 million and $11.1 million for the nine-month periods ended September 30, 2010 and 2009, respectively. Interest expense increased approximately $13.4 million as Legacy recorded $10.8 million of interest expense related to the interest rate swap mark-to-market adjustment for the nine-month period ended September 30, 2010 compared to interest income of $1.8 million due to the interest rate swap mark-to-market adjustment for the nine-month period ended September 30, 2009.

Non-GAAP Financial Measures

For the three months ended September 30, 2010 and 2009, respectively, Adjusted EBITDA increased 16% to $35.7 million from $30.8 million primarily due to increased revenues from our oil, NGL and natural gas sales in the three months ended September 30, 2010 compared to the three months ended September 30, 2009, partially offset by higher production expenses. These increased revenues more than offset the decreased realized commodity derivative settlements of approximately $3.8 million from $10.1 million to $6.3 million for the three months ended September 30, 2009 and 2010, respectively. For the three months ended September 30, 2010 and 2009, respectively, Distributable Cash Flow decreased 5% to $22.2 million from $23.3 million as increases in development capital expenditures more than offset increases in Adjusted EBITDA. Due to favorable commodity prices and capital costs, Legacy increased capital expenditures for the three months ended September 30, 2010 to $9.0 million from $3.0 million for the three months ended September 30, 2009.

For the nine months ended September 30, 2010 and 2009, respectively, Adjusted EBITDA increased 15% to $100.7 million from $87.6 million primarily due to increased revenues from our oil, NGL and natural gas sales in the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009, partially offset by higher production expenses. These increased revenues more than offset the decreased realized commodity derivative settlements of approximately $30.5 million from $45.8 million to $15.3 million for the nine months ended September 30, 2009 and 2010, respectively. For the nine months ended September 30, 2010 and 2009, respectively, Distributable Cash Flow increased 7% to $67.5 million from $62.8 million due to higher Adjusted EBITDA and lower cash interest expense, which more than offset higher development capital expenditures and cash settlements of LTIP unit awards.

The management of Legacy Reserves LP uses Adjusted EBITDA and Distributable Cash Flow as a tool to provide additional information and metrics relative to the performance of Legacy's business, such as the cash distributions Legacy expects to pay to its unitholders, as well as its ability to meet debt covenant compliance tests. Legacy's management believes that these financial measures help investors evaluate whether or not cash flow is being generated at a level that can sustain or support an increase in quarterly distribution rates. Adjusted EBITDA and Distributable Cash Flow 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" and "Distributable Cash Flow," both of which are non-GAAP measures, to their nearest comparable GAAP measure. "Adjusted EBITDA" and "Distributable Cash Flow" should not be considered as alternatives to GAAP measures, such as net income, operating income or any other GAAP measure of liquidity or financial performance.

Adjusted EBITDA is defined in Legacy's revolving credit facility 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;
- Unit-based compensation expense related to LTIP unit awards accounted for under the equity or liability methods;
- Unrealized (gain) loss on oil and natural gas derivatives; and
- Equity in (income) loss of partnership.

Distributable Cash Flow is defined as Adjusted EBITDA less:

- Cash interest expense;

- Cash income taxes;
- Cash settlements of LTIP unit awards; and
- Development capital expenditures.

The following table presents a reconciliation of Legacy's consolidated net income (loss) to Adjusted EBITDA and Distributable Cash Flow for the three and nine months ended September 30, 2010 and 2009, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(dollars in thousands)			
Net income (loss)	$ (20,185)	$ (851)	$ 29,481	$ (54,354)
Plus:				
Interest expense	8,215	8,612	24,553	11,110
Income tax expense (benefit)	(83)	135	544	406
Depletion, depreciation, amortization and accretion	16,175	13,302	45,356	43,472
Impairment of long-lived assets	4,173	2,375	12,560	3,982
Gain on disposal of assets	-	(6)	-	(66)
Equity in income of partnership	(22)	(16)	(71)	(13)
Unit-based compensation expense	1,310	1,590	3,288	2,126
Unrealized (gain)/loss on oil and natural gas derivatives	26,163	5,674	(15,024)	80,974
Adjusted EBITDA	$ 35,746	$ 30,815	$ 100,687	$ 87,637
Less:				
Cash interest expense	4,378	4,492	11,819	14,102
Cash settlements of LTIP unit awards	134	66	2,044	302
Development capital expenditures	9,026	2,979	19,288	10,395
Distributable Cash Flow	$ 22,208	$ 23,278	$ 67,536	$ 62,838

Capital Resources and Liquidity

Legacy's primary sources of capital and liquidity have been bank borrowings, cash flow from operations, its private equity offerings in March 2006 and November 2007, the Initial Public Offering in January 2007 and its public equity offerings in September 2009 and January 2010. To date, Legacy's primary use of capital has been for acquisitions, repayment of bank borrowings and development of oil and natural gas properties.

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 credit facility imposes specific restrictions on our ability to obtain additional debt financing. See " – Financing Activities – Our Revolving Credit Facility." Our commodity derivatives position, which we use to mitigate commodity price volatility and support our borrowing capacity, contributed $15.3 million and $45.8 million of cash settlements during the nine months ended September 30, 2010 and 2009, respectively. Based upon current oil and natural gas price expectations for the year ending December 31, 2010, 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 $410 million. As of November 4, 2010, we had $119.9 million available for borrowing under our credit facility. Based on their commodity price expectations, our lenders redetermine the borrowing base semi-annually, with the next redetermination scheduled for April 2011. Please read "— Financing Activities — Our Revolving Credit Facility."

Cash Flow from Operations

Legacy's net cash provided by operating activities was $78.9 million and $19.8 million for the nine-month periods ended September 30, 2010 and 2009, respectively, with the 2010 period being favorably impacted by higher commodity prices, as the net cash amount for 2010 and 2009 does not include cash settlements received of $15.3 million and $45.8 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 $182.7 million for the nine-month period ended September 30, 2010. The total includes $163.4 million for the acquisition of oil and natural gas properties in the Wyoming Acquisition and 18 individually immaterial acquisitions and $19.3 million of development projects. Legacy's cash capital expenditures were $16.3 million for the nine-month period ended September 30, 2009. The total includes $10.4 million of development projects, $5.6 million for three individually immaterial acquisitions and $0.3 million in purchase price adjustments on previous acquisitions.

Our capital expenditure budget, which predominantly consists of drilling, recompletion and capital workover projects, is currently $31 million for the year ending December 31, 2010, of which $19.3 million has been completed during the nine-months ended September 30, 2010. Oilfield service delays in both rigs and fracture stimulation crews during the first half of 2010 caused our capital expenditures budget to be heavily weighted toward the second half of 2010. Our remaining borrowing capacity under our revolving credit facility is $119.9 million as of November 4, 2010. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. We may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions 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, 2010, 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 $11.7 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, NGL and natural gas derivative transactions to reduce the impact of oil, NGL 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 that we typically experience in the Permian Basin. For the nine-month period ended September 30, 2010 and 2009 we had cash settlements of $15.3 million and $45.8 million, respectively, related to our commodity derivative settlements. At September 30, 2010, we had in place oil and natural gas derivatives covering significant portions of our estimated 2010 through 2014 oil, NGL and natural gas production. As of November 4, 2010, we have derivative contracts covering approximately 74% of our remaining expected oil, natural gas liquid and natural gas production for 2010. As of November 4, 2010, we also have derivative contracts covering approximately 47% of our currently expected oil and natural gas production for 2011 through 2014 from existing estimated total proved reserves.

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 financial institutions deemed by management as competent and competitive market makers. In addition, these counterparties are members of 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 November 4, 2010, through December 31, 2015. We use derivatives, including swaps, collars 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 settled based upon the monthly average closing price of the front-month NYMEX WTI oil contract price of oil at Cushing, Oklahoma, and NYMEX Henry Hub, West Texas Waha, Rocky Mountain CIG and ANR-Oklahoma prices of natural gas on the average of the three final trading days of the month and settlement occurs on the fifth day of the production month.

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
October - December 2010	500,959	$82.21	$60.15 - $140.00
2011 (a)	1,888,612	$88.08	$67.33 - $140.00
2012 (a)	1,324,466	$82.01	$67.72 - $109.20
2013 (a)	881,445	$83.62	$80.10 - $89.35
2014	356,710	$87.88	$87.50 - $90.50

(a) On October 6, 2010, as part of an oil swap transaction entered into with a counterparty, we sold two call options to the counterparty that allow the counterparty to extend a swap transaction covering calendar year 2011 to either 2012, 2013 or both calendar years. The counterparty must exercise or decline the option covering calendar year 2012 on December 30, 2011 and the option covering calendar year 2013 on December 31, 2012. If exercised, we would pay the counterparty floating prices and receive a fixed price of $98.25 on annual notional volumes of 183,000 Bbls in 2012 and 182,500 Bbls in 2013. The premium paid by the counterparty for the two call options was received by us as an increase in the fixed price that we will receive pursuant to the 2011 swap of $98.25 per Bbl on 182,500 Bbls, or 500 Bbls per day, rather than the prevailing market price of approximately $87.00 per Bbl.

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
October - December 2010	983,094	$7.18	$5.33 - $8.88
2011	3,038,316	$7.49	$5.74 - $8.70
2012	2,357,990	$7.49	$5.72 - $8.70
2013	1,402,754	$6.58	$5.78 - $6.89
2014	609,104	$6.36	$5.95 - $6.47

In July 2006, we entered into natural gas basis derivatives to receive floating NYMEX natural gas prices less a fixed basis differential and pay prices based on the floating Waha index, a natural gas hub in West Texas. The prices that we receive for our natural gas sales follow Waha more closely than NYMEX. The basis derivatives thereby provide a better match between our natural gas sales and the settlement payments on our natural gas derivatives. The following table summarizes, for the periods indicated, our NYMEX-Waha basis derivatives currently in place as of November 4, 2010, through December 31, 2010:

Calendar Year	Annual Volumes (MMBtu)	Basis Differential per MMBtu
October - December 2010	300,000	($0.57)

On June 24, 2008, we entered into a NYMEX West Texas Intermediate crude oil derivative collar contract that combines a put option or "floor" with a call option or "ceiling." The following table summarizes the oil collar contract currently in place as of November 4, 2010, through December 31, 2012:

Calendar Year	Volumes (Bbls)	Floor Price	Ceiling Price
October - December 2010	18,100	$120.00	$156.30
2011	68,300	$120.00	$156.30
2012	65,100	$120.00	$156.30

On May 3, 2010, we entered into two separate NYMEX West Texas Intermediate crude oil derivative three-way collar contracts. On October 6, 2010, we entered into eight additional NYMEX West Texas Intermediate crude oil derivative three-way collar contracts. Each contract combines a long put, a short put and a short call. The use of the long put combined with the short put allows us to purchase a short call at a higher price thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside coverage to the difference between the long put and the short put if the price of NYMEX West Texas Intermediate crude oil drops below the price of the short put. This 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, or the floating price plus $25 per barrel ($85-$60). The following table summarizes the three-way oil collar contracts currently in place as of November 4, 2010, through December 31, 2015:

Calendar Year	Volumes (Bbls)	Average Short Put	Average Long Put	Average Short Call
2012	73,200	$60.00	$85.00	$99.81
2013	270,370	$60.00	$85.00	$107.02
2014	354,380	$60.00	$85.00	$115.38
2015	331,550	$60.00	$85.00	$118.91

Financing Activities

Legacy's net cash provided by financing activities was $85.4 million for the nine months ended September 30, 2010, compared to cash used of $47.8 million for the nine months ended September 30, 2009. During the nine months ended September 30, 2010, total net borrowings under the Credit Agreement were $53 million, comprised of borrowings of $231 million and repayments of $178 million. Our January 2010 public equity offering yielded net cash proceeds of $95.4 million, which were used to pay down our balance on the Credit Agreement. Subsequent to the pay down, we incurred borrowings under the Credit Agreement to finance the Wyoming Acquisition and 18 other individually immaterial acquisitions. Offsetting the net cash proceeds from net borrowings and our January 2010 public equity offering during the nine months ended September 30, 2010, was cash used in the amount of $62.6 million for distributions to unitholders. Cash used in financing activities during the nine months ended September 30, 2009, included $52 million in net repayments under the Credit Agreement, $57.3 million in cash proceeds from our September 2009 public equity offering and $48.5 million for distributions to unitholders.

Our Revolving Credit Facility

On March 27, 2009, we entered into a three-year, $600 million secured revolving credit facility ("Credit Agreement") and retained BNP Paribas as administrative agent to replace our previous four-year, $300 million revolving credit facility with BNP Paribas as administrative agent. 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. The amount available for borrowing at any one time is limited to the borrowing base, which was initially set at $340 million, increased on March 31, 2010 to $410 million and maintained at $410 million in connection with the October 2010 semi-annual redetermination. 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 the borrowing base must be approved by 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. 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 $250 million in aggregate principal amount of senior notes, subject to specified conditions (including that upon issuance of such senior notes our borrowing base would be reduced by an amount equal to 25% of the stated principal amount of the senior notes, or $62.5 million if $250 million of senior notes are issued). 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:

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with respect to ABR loans, the alternate base rate equals the highest of the prime rate, the Federal funds effective rate plus 0.50%, the one-month London interbank rate ("LIBOR") plus 1.50% or the reference bank cost of funds rate, plus an applicable margin ranging from and including 0.75% and 1.50% per annum, determined by the percentage of the borrowing base then in effect that is drawn, or

- with respect to any Eurodollar loans, one-, two-, three- or six-month LIBOR plus an applicable margin ranging from and including 2.25% and 3.0% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

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

Our revolving credit facility 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 its business; or
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

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

- consolidated net income (loss) in total over the last four quarters plus interest expense, income taxes, depreciation, depletion, amortization and other similar charges excluding unrealized gains and losses under ASC 815, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures ("EBITDA"), to interest expense in total over the last four quarters of not less than 2.5 to 1.0;

- total debt as of the last day of the most recent quarter to EBITDA in total over the last four quarters of not more than 3.75 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.

Interest expense, as defined in the Credit Agreement, differs from interest expense for GAAP purposes, most notably in that it excludes mark-to-market adjustments for interest rate derivatives.

If an event of default exists under our revolving credit facility, 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 $1.0 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 27, 2009 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 $1.0 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 $1.0 million in any year.

As of September 30, 2010, Legacy was in compliance with all financial and other covenants of the credit facility.

Our Shelf Registration Statement

During the second quarter of 2008, Legacy filed a registration statement with the SEC which registered securities in an aggregate offering amount of up to $500 million of any combination of debt securities and units. Net proceeds, terms and pricing of the offering of securities issued under the 2008 shelf registration statement are determined at the time of any offering. The filing of the shelf registration statement does not in itself indicate that Legacy will or could sell any such securities. Legacy’s ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or units will depend upon, among other things, market conditions and sufficient demand at prices acceptable to Legacy.

In September of 2009, Legacy issued 3,795,000 units in a public offering at an undiscounted price of $15.85 per unit, for gross proceeds of $60.2 million, before underwriting discount and offering costs.

In January of 2010, Legacy issued 4,887,500 units in a public offering at an undiscounted price of $20.42 per unit, for gross proceeds of $99.8 million, before underwriting discount and offering costs.

As a result of these offerings, Legacy has approximately $340 million remaining available for issuance under its 2008 shelf registration statement as of November 4, 2010.

Off-Balance Sheet Arrangements

None.

Critical Accounting Policies and Estimates

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

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

Please read Note 1 of the Notes to the Condensed Consolidated Financial Statements here and in our Annual Report on Form 10-K for the period ended December 31, 2009 for a detailed discussion of all significant accounting policies that we employ and related estimates made by management.

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

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

Effect if Different Assumptions Used: Units-of-production method to deplete our oil and natural gas properties — A 10% increase or decrease in reserves would have decreased or increased, respectively, our depletion expense for the nine-month period ended September 30, 2010 by approximately 10%.

Nature of Critical Estimate Item: Asset Retirement Obligations — We have certain obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. We adopted ASC 410-20, Accounting for Asset Retirement Obligations, effective January 1, 2003. ASC 410-20 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets (“asset retirement obligations” or “ARO”). Primarily, ASC 410-20 requires us to estimate asset retirement costs for all of our assets, adjust those costs for inflation to the forecasted abandonment date, discount that amount using a credit-adjusted risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an ARO liability in that amount with a corresponding addition to our asset value. When new obligations are incurred, i.e. a new well is drilled or acquired, we add a layer to the ARO liability. We then accrete the liability layers quarterly using the applicable period-end effective credit-adjusted risk-free rates for each layer. Should either the estimated life or the estimated abandonment costs of a property change materially upon our quarterly review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted risk-free rate. The carrying value of the ARO is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost. Thus, abandonment costs will almost always approximate the estimate. When well obligations are relieved by sale of the property or plugging and abandoning the well, the related liability and asset costs are removed from our balance sheet.

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

Effect if Different Assumptions Used: Since there are so many variables in estimating AROs, we attempt to limit the impact of management’s judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. Unless we expect a well’s plugging to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of a discount factor and present value calculation, could differ from actual results, despite our efforts to make an accurate estimate. We engage an independent engineering firm to evaluate our properties annually. We use the remaining estimated useful life from the year-end reserve report by our independent reserve engineers in estimating when abandonment could be expected for each property. We expect to see our calculations impacted significantly if interest rates continue to rise, as the credit-adjusted risk-free rate is one of the variables used on a quarterly basis.

Nature of Critical Estimate Item: Derivative Instruments and Hedging Activities — We periodically use derivative financial instruments to achieve a more predictable cash flow from our oil, NGL and natural gas production and interest expense by reducing our exposure to price fluctuations and interest rate changes. Currently, these transactions are swaps and collars whereby we exchange our floating price for our oil, NGL and natural gas for a fixed price and floating interest rates for a fixed rate with qualified and creditworthy counterparties (currently BNP Paribas, Bank of America Merrill Lynch, KeyBank, Wells Fargo, BBVA Compass Bank, Royal Bank of Canada and The Bank of Nova Scotia). Our existing oil, NGL, natural gas derivatives and interest rate swaps and oil collars are with members of our lending group which enables us to avoid margin calls for out-of-the-money mark-to-market positions.

We do not specifically designate derivative instruments as cash flow hedges, even though they reduce our exposure to changes in oil, NGL and natural gas prices and interest rate changes. Therefore, the mark-to-market of these instruments is recorded in current earnings. We use market value estimates prepared by a third party firm, which specializes in valuing derivatives, and validate these estimates by comparison to counterparty estimates as the basis for these end-of-period mark-to-market adjustments. When we record a mark-to-market adjustment resulting in a loss in a current period, these unrealized losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods. As shown in the tables above, we have hedged a significant portion of our future production through 2015. As oil, NGL and natural gas prices rise and fall, our future cash obligations related to these derivative transactions will rise and fall.

Recently Issued Accounting Pronouncements

In January 2010, the FASB issued authoritative guidance intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels, the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance was effective for Legacy on January 1, 2010, except for the disclosures about purchases, sales, issuances and settlements in the Level 3 reconciliation, which will be effective for interim and annual periods beginning after December 15, 2010. As this guidance provides only disclosure requirements, the adoption of this standard did not impact Legacy's results of operations, cash flows or financial position.

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 spot 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 whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into put options, whereby we pay a premium in exchange for the right to receive a fixed price at a future date. At the settlement date we receive the excess, if any, of the fixed floor over the floating rate. 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 September 30, 2010, the fair market value of Legacy's commodity derivative positions was a net asset of $21.9 million based on NYMEX futures prices from October 2010 to December 2015 for both oil and natural gas. As of December 31, 2009, the fair market value of Legacy's commodity derivative positions was a net asset of $6.9 million based on NYMEX futures prices from January 2010 to December 2014 for both oil and natural gas. The futures market prices of oil and natural gas decreased from December 31, 2009 to September 30, 2010 across the overlapping periods of the time frames referenced above over which our commodity derivatives are in place. Due to our asset position on commodity derivatives we routinely monitor the credit default risk of our counterparties via risk monitoring services. For more discussion about our derivative transactions and to see a table listing the oil and natural gas derivatives from October 2010 through December 31, 2015, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations— Investing Activities.”

Interest Rate Risks

At September 30, 2010, Legacy had debt outstanding of $290 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by Legacy for the nine-month period ended September 30, 2010 was 3.4%. A 1% increase in LIBOR on Legacy’s outstanding debt as of September 30, 2010 would result in an estimated $0.26 million increase in annual interest expense as Legacy has entered into interest rate swaps to mitigate the volatility of interest rates through December of 2013 on $264 million of floating rate debt to a weighted-average fixed rate of 3.05%.

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 September 30, 2010. 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 September 30, 2010, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

In addition to the other 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, 2009 and our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010, 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.

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. (Removed and Reserved).

Item 5. Other Information.

None.

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)
4.1	Registration Rights Agreement dated June 29, 2006 between Henry Holding LP and Legacy Reserves LP and Legacy Reserves GP, LLC (the "Henry Registration Rights Agreement") (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.2)
4.2	Registration Rights Agreement dated March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (the "Founders Registration Rights Agreement") (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.3)
4.3	Registration Rights Agreement dated April 16, 2007 by and among Nielson & Associates, Inc., Legacy Reserves GP, LLC and Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP's Quarterly Report on Form 10-Q (File No. 001-33249) filed May 14, 2007, Exhibit 4.4)
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)

* Filed herewith

SIGNATURES

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

LEGACY RESERVES LP

By: Legacy Reserves GP, LLC, its General Partner

November 5, 2010	By:	/s/ Steven H. Pruett Steven H. Pruett President, Chief Financial Officer and Secretary (On behalf of the Registrant and as Principal Financial Officer)