LEGACY RESERVES LP
Form 10-Q
May 06, 2011

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

FORM 10-Q

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

SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2011

or

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

SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-33249

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

Delaware (State or other jurisdiction of incorporation or organization)	16-1751069 (I.R.S. Employer Identification No.)
303 W. Wall, Suite 1400 Midland, Texas (Address of principal executive offices)	79701 (Zip code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

x Yes o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

£ 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

43,612,479 units representing limited partner interests in the registrant were outstanding as of May 5, 2011.

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GLOSSARY OF TERMS

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

Bcf. Billion cubic feet.

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

Boe/d. Barrels of oil equivalent per day.

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

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

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

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

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

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

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

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

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.

NGL or natural gas liquids. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX. New York Mercantile Exchange.

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

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

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

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

Part I – FINANCIAL INFORMATION

Item 1. Financial Statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)
ASSETS

	March 31, 2011	December 31, 2010
	(In thousands)	
Current assets:		
Cash and cash equivalents	$1,765	$3,478
Accounts receivable, net:		
Oil and natural gas	35,259	27,050
Joint interest owners	13,351	10,378
Other	317	91
Fair value of derivatives (Notes 6 and 7)	4,861	7,763
Prepaid expenses and other current assets	2,386	1,838
Total current assets	57,939	50,598
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties, at cost, using the successful efforts method of accounting	1,199,115	1,174,498
Unproved properties	12,543	12,543
Accumulated depletion, depreciation and amortization	(362,341)	(343,205)
	849,317	843,836
Other property and equipment, net of accumulated depreciation and amortization of $2,723 and $2,437, respectively	2,933	2,917
Deposits on pending acquisitions	—	112
Operating rights, net of amortization of $2,655 and $2,529, respectively	4,362	4,488
Fair value of derivatives (Notes 6 and 7)	—	4,000
Other assets, net of amortization of $5,277 and $4,809, respectively	7,949	3,331
Investment in equity method investee	173	144
Total assets	$922,673	$909,426

See accompanying notes to condensed consolidated financial statements.

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

	March 31, 2011	December 31, 2010
	(In thousands)	
Current liabilities:		
Accounts payable	$4,746	$631
Accrued oil and natural gas liabilities	40,409	29,654
Fair value of derivatives (Notes 6 and 7)	42,780	14,882
Asset retirement obligation (Note 8)	18,246	18,333
Other (Note 10)	7,541	9,455
Total current liabilities	113,722	72,955
Long-term debt (Note 2)	339,000	325,000
Asset retirement obligation (Note 8)	93,858	92,929
Fair value of derivatives (Notes 6 and 7)	66,185	25,540
Other long-term liabilities	1,276	1,263
Total liabilities	614,041	517,687
Commitments and contingencies (Note 5)		
Unitholders' equity:		
Limited partners' equity - 43,531,276 and 43,528,776 units issued and outstanding at March 31, 2011 and December 31, 2010, respectively	308,571	391,662
General partner's equity (approximately 0.05%)	61	77
Total unitholders' equity	308,632	391,739
Total liabilities and unitholders' equity	$922,673	$909,426

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended March 31,	
	2011	2010
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$59,265	$37,748
Natural gas liquids sales (NGL)	4,250	3,750
Natural gas sales	9,253	8,169
Total revenues	72,768	49,667
Expenses:		
Oil and natural gas production	23,757	15,070
Production and other taxes	4,357	2,919
General and administrative	6,358	4,761
Depletion, depreciation, amortization and accretion	19,560	13,115
Impairment of long-lived assets	1,047	7,916
(Gain) loss on disposal of assets	(409)	14
Total expenses	54,670	43,795
Operating income	18,098	5,872
Other income (expense):		
Interest income	2	3
Interest expense (Notes 2, 6 and 7)	(3,377)	(7,333)
Equity in income of partnership	29	23
Realized and unrealized net gains (losses) on commodity derivatives (Notes 6 and 7)	(75,456)	11,861
Other	4	(33)
Income (loss) before income taxes	(60,700)	10,393
Income tax (expense) benefit	330	(173)
Net income (loss)	$(60,370)	$10,220
Income (loss) per unit - basic and diluted (Note 9)	$(1.39)	$0.26
Weighted average number of units used in computing net income (loss) per unit -		
basic	43,529	39,216
diluted	43,529	39,219

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
FOR THE THREE MONTHS ENDED MARCH 31, 2011
(UNAUDITED)

	Number of Limited Partner Units	Limited Partner	General Partner	Total Unitholders' Equity
	(In thousands)			
Balance, December 31, 2010	43,529	$391,662	$77	$391,739
Compensation expense on restricted unit awards issued to employees	—	168	—	168
Vesting of restricted units	3	—	—	—
Net costs of equity offering	—	(8)	—	(8)
Net distributions to unitholders, $0.525 per unit	—	(22,906)	9	(22,897)
Net loss	—	(60,345)	(25)	(60,370)
Balance, March 31, 2011	43,532	$308,571	$61	$308,632

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended March 31, 2011	2010
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$(60,370)	$10,220
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	19,560	13,115
Amortization of debt issuance costs	468	460
Impairment of long-lived assets	1,047	7,916
(Gain) loss on derivatives	73,767	(8,670)
Equity in income of partnership	(29)	(23)
Unit-based compensation	(375)	1,022
(Gain) loss on disposal of assets	(409)	14
Changes in assets and liabilities:		
Increase in accounts receivable, oil and natural gas	(8,209)	(5,771)
(Increase) decrease in accounts receivable, joint interest owners	(2,973)	86
(Increase) decrease in accounts receivable, other	(226)	21
(Increase) decrease in other current assets	(949)	158
Increase in accounts payable	4,115	645
Increase in accrued oil and natural gas liabilities	10,757	5,334
Decrease in other liabilities	(1,756)	(1,218)
Total adjustments	94,788	13,089
Net cash provided by operating activities	34,418	23,309
Cash flows from investing activities:		
Investment in oil and natural gas properties	(24,027)	(131,484)
Decrease in deposits on pending acquisitions	112	5,800
Investment in other equipment	(302)	(46)
Net cash settlements on commodity derivatives	1,676	4,789
Net cash provided by (used in) investing activities	(22,541)	(120,941)
Cash flows from financing activities:		
Proceeds from long-term debt	55,000	143,000
Payments of long-term debt	(41,000)	(116,000)
Payments of debt issuance costs	(4,685)	(368)
Proceeds from issuance of units, net	(8)	95,436
Distributions to unitholders	(22,897)	(20,837)
Net payments of LTIP unit awards	—	(1,702)
Net cash provided by (used in) financing activities	(13,590)	99,529
Net increase in cash and cash equivalents	(1,713)	1,897
Cash and cash equivalents, beginning of period	3,478	4,217
Cash and cash equivalents, end of period	$1,765	$6,114
Non-Cash Investing and Financing Activities:		
Asset retirement obligation costs and liabilities	$(848)	$363

Asset retirement obligations associated with property acquisitions	$1,438	$5,148
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, 2010.

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 $66\frac{2}{3}$ percent of the outstanding units, including units held by LRLP's general partner and its affiliates, provided that a unit majority has elected a successor general partner.

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

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

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

The accompanying condensed consolidated financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred. These condensed consolidated financial statements as of March 31, 2011 and for the three months ended March 31, 2011 and 2010 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 months ended March 31, 2011 and 2010.

(b) Recently Issued Accounting Pronouncements

In December, 2010, the FASB issued ASU 2010-29, Business Combinations (Topic 805) Disclosure of Supplementary Pro Forma Information for Business Combinations, which addresses the diversity in practice regarding the interpretation of the pro forma revenue and earnings disclosure requirements for business combinations. The amended guidance specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity

as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Additionally, the amended guidance expands the supplemental pro forma disclosures under Topic 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings.
The amended guidance is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010, which is the Partnership's fiscal period beginning January 1, 2011. Early adoption is permitted. Legacy adopted the amended guidance on January 1, 2011, the adoption of which did not impact Legacy's results of operations, cash flows or financial position as this guidance provides only disclosure requirements.

(2) Credit Facility

On March 27, 2009, Legacy entered into a three-year secured revolving credit facility with BNP Paribas as administrative agent (the “Previous Credit Agreement”). Borrowings under the Previous Credit Agreement were set to mature on April 1, 2012. The Previous Credit Agreement permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $600 million. The borrowing base under the Previous Credit Agreement, initially set at $340 million, was $410 million on March 9, 2011. Under the Previous Credit Agreement, interest on debt outstanding was charged based on Legacy’s selection of a LIBOR rate plus 2.25% to 3.0%, or the alternate base rate (“ABR”) which equaled 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%.

On March 10, 2011, Legacy entered into an amended and restated five-year $1 billion secured revolving credit facility with BNP Paribas as administrative agent (the "Current Credit Agreement"). Borrowings under the Current Credit Agreement mature on March 10, 2016. The amount available for borrowing at any one time is limited to the borrowing base, currently at $500 million, with a $2 million sub-limit for letters of credit. The borrowing base is subject to semi-annual re-determinations on April 1 and October 1 of each year, commencing October 1, 2011. Additionally, either Legacy or the lenders may, once during each calendar year, elect to re-determine the borrowing base between scheduled re-determinations. Legacy also has the right, once during each calendar year, to request the re-determination 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. Under the Current Credit Agreement, interest on debt outstanding is charged based on Legacy's selection of a one-, two-, three- or six-month LIBOR rate plus 1.75% to 2.75%, or the ABR which equals the highest of the prime rate, the Federal funds effective rate plus 0.50% or one-month LIBOR plus 1.00%, plus an applicable margin from 0.75% to 1.75% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

The borrowing base permits Legacy to issue up to $500 million in aggregate principal amount of senior notes or new debt issued to refinance senior notes, subject to specified conditions in the Current Credit Agreement, which include that upon the issuance of such senior notes or new debt, the borrowing base will be reduced by an amount equal to (i) in the case of senior notes, 25% of the stated principal amount of the senior notes and (ii) in the case of new debt, 25% of the portion of the new debt that exceeds the original principal amount of the senior notes.

As of March 31, 2011, Legacy had outstanding borrowings of $339.0 million at a weighted-average interest rate of 2.56%. Legacy had approximately $160.9 million of availability remaining under the Current Credit Agreement as of March 31, 2011. For the three month period ended March 31, 2011, Legacy paid in cash $2.7 million of interest expense on the Previous and Current Credit Agreements. Legacy’s revolving credit facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

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

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

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 March 31, 2011, Legacy was in compliance with all aspects of the Current Credit Agreement.

Long-term debt consists of the following as of March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	(In thousands)	
Legacy Facility- due March 2016	$339,000	$325,000

(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 $125.5 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 Previous 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	$124,115
Unproved properties	6,143
Total assets	130,258
Future abandonment costs	(4,709)
Fair value of net assets acquired	$125,549

COG Acquisition

On December 22, 2010, Legacy purchased certain oil and natural gas properties located primarily in the Permian Basin from COG Operating LLC, a wholly owned subsidiary of Concho Resources Inc., for a net cash purchase price of $100.8 million (the "COG Acquisition" and together with the Wyoming Acquisition, the "Wyoming and COG Acquisitions"). The purchase price was financed partially with net proceeds from Legacy's November 2010 public offering of units and the remainder with borrowings from the Previous Credit Agreement. The effective date of this purchase was October 1, 2010. The operating results from these COG Acquisition properties have been included from their acquisition on December 22, 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	$104,248
Unproved properties	5,072
Total assets	109,320
Future abandonment costs	(8,506)
Fair value of net assets acquired	$100,814

Pro Forma Operating Results

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

	Three Months Ended March 31, 2010
	(In thousands)
Revenues	$60,931
Net income	$12,997
Income per unit - basic and diluted:	$0.33
Units used in computing income per unit:	
basic	39,216
diluted	39,219

Post-Acquisition Operating Results

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

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
Wyoming Acquisition		
Revenues	$8,755	$4,253
Excess of revenues over direct operating expenses	$4,090	$2,376
COG Acquisition		
Revenues	$6,037	$—
Excess of revenues over direct operating expenses	$3,265	$—

(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 $28,034, without respect to property taxes, insurance and operating expenses. The lease expires in September 2015.

Legacy uses Lynch, Chappell and Alsup for legal services. Alan Brown, son of Dale Brown, a director of Legacy, and 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 $32,502 and $92,430 for the three months ended March 31, 2011 and 2010, 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, except as discussed in Note 12, 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. See Note 12 for further discussion.

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 natural gas derivative swaps for those derivatives indexed to the West Texas Waha, ANR-Oklahoma and CIG indices, commodity collars and oil swaptions. 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 March 31, 2011:

	Fair Value Measurements at March 31, 2011 Using			
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Total Carrying Value as off

Description	(Level 1) (In thousands)	(Level 2)	(Level 3)	March 31, 2011
LTIP liability (a)	$—	$(5,277)	$—	$(5,277)
Oil, NGL and natural gas derivative swaps	—	(95,634)	15,572	(80,062)
Oil and natural gas collars	—	—	(6,197)	(6,197)
Oil Swaptions	—	—	(5,538)	(5,538)
Interest rate swaps	—	(12,307)	—	(12,307)
Total	$—	$(113,218)	$3,837	$(109,381)

(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 March 31,	
	2011	2010
	(In thousands)	
Beginning balance	$24,641	$17,791
Total gains or (losses)	(17,463)	8,208
Settlements	(3,341)	(1,625)
Ending balance	$3,837	$24,374
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of March 31, 2011 and 2010	$(20,804)	$6,583

Fair Value on a Non-Recurring Basis

Legacy follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. As it relates to Legacy, the statement 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 three-month period ended March 31, 2011 include:

	Fair Value Measurements at March 31, 2011 Using			
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Total Carrying Value as of
Description	(Level 1)	(Level 2)	(Level 3)	March 31, 2011
	(In thousands)			
Assets:				
Proved oil and natural gas properties - Impairment (a)	$—	$—	$512	$512
Proved oil and natural gas properties - Acquisitions (b)	$—	$—	$12,118	$12,118
Total	$—	$—	$12,630	$12,630

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 three-month period ended March 31, 2011, Legacy incurred impairment charges of $1.05

million as oil and natural gas properties with a net cost basis of $1.6 million were written down to their fair value of $0.5 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 three-month period ended March 31, 2011, Legacy acquired oil and natural gas properties with a fair value of $12.1 million in six 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, swaptions 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 months ended March 31, 2011 and 2010.

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 months ended March 31, 2011 and 2010, 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 March 31,	
	2011	2010
	(In thousands)	
Crude oil derivative contract settlements	$(1,140)	$2,907
Natural gas liquid derivative contract settlements	—	(39)
Natural gas derivative contract settlements	2,816	1,921
Total commodity derivative contract settlements	1,676	4,789
Unrealized change in fair value - oil contracts	(74,108)	(828)
Unrealized change in fair value - natural gas liquid contracts	—	39
Unrealized change in fair value - natural gas contracts	(3,024)	7,861
Total unrealized change in fair value of commodity derivative contracts	(77,132)	7,072
Total realized and unrealized gain (loss) on commodity derivative contracts	$(75,456)	$11,861

As of March 31, 2011, 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
April - December 2011(a)	1,634,501	$88.76	$67.33 - $140.00
2012(a)	1,511,121	$83.05	$67.72 - $109.20
2013(a)	1,051,243	$84.73	$80.10 - $90.50
2014	513,514	$88.68	$87.50 - $90.50
2015	145,051	$90.50	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 paid to us in the form of 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. These additional potential volumes are not reflected in the above table.

As of March 31, 2011, Legacy had the following NYMEX West Texas Intermediate crude oil derivative collar contracts that combine a long put option or “floor” with a short call option or “ceiling” as indicated below:

Calendar Year	Volumes (Bbls)	Floor Price	Ceiling Price
April - December 2011	51,400	$120.00	$156.30
2012	65,100	$120.00	$156.30

As of March 31, 2011, Legacy had the following NYMEX West Texas Intermediate crude oil derivative three-way collar contracts that combine a long put, a short put and a short call as indicated below:

Calendar Year	Volumes (Bbls)	Average Short Put	Average Long Put	Average Short Call
2012	256,200	$65.36	$91.43	$109.25
2013	379,870	$60.72	$86.44	$107.97
2014	463,880	$60.59	$86.18	$114.70
2015	441,050	$61.24	$86.24	$118.65

As of March 31, 2011, Legacy had the following NYMEX West Texas Waha, ANR-OK and CIG-Rockies natural gas swaps paying floating natural gas prices and receiving fixed prices for a portion of its future natural gas production as indicated below:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
April - December 2011	3,772,462	$6.23	$4.15 - $8.70
2012	2,906,990	$6.97	$4.72 - $8.70
2013	1,950,254	$6.13	$5.00 - $6.89
2014	609,104	$6.36	$5.95 - $6.47

As of March 31, 2011, Legacy had the following West Texas Waha natural gas derivative collar contract that combines a long put option or "floor" with a short call option or "ceiling" as indicated below:

Calendar Year	Volumes (MMBtu)	Floor Price	Ceiling Price
2012	360,000	$4.00	$5.45

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 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 2009 and ending in November 2013.

On March 14, 2008, Legacy entered into a LIBOR interest rate swap beginning in April 2008 and extending through April 2011. On January 28, 2009, Legacy revised the LIBOR interest rate swap extending the term through April 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 2009 and ending in April 2013. Prior to April 2009, the swap was settled on a quarterly basis.

On October 6, 2008, Legacy entered into two LIBOR interest rate swaps beginning in October 2008 and extending through October 2011. In January 2009, Legacy revised these LIBOR interest rate swaps extending the termination date through October 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 2009 and ending in October 2013.

On December 16, 2008, Legacy entered into a LIBOR interest rate swap beginning in December 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 2009 and ending in December 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.

Legacy does not specifically designate these derivative transactions as cash flow hedges, even though they reduce its exposure to changes in interest rates. Therefore, the mark-to-market of these instruments is recorded in current earnings as 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 March 31,	
	2011	2010
	(In thousands)	
Interest rate swap settlements	$1,827	$1,856
Unrealized change in fair value - interest rate swaps	(1,689)	3,191
Total increase to interest expense, net	$138	$5,047

The table below summarizes the interest rate swap position as of March 31, 2011.

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at March 31, 2011
(Dollars in thousands)				
$29,000	4.090%	10/16/2007	10/16/2013	$(2,151)
$13,000	4.110%	11/16/2007	11/16/2013	(986)
$12,000	4.110%	11/28/2007	11/28/2013	(899)
$60,000	2.650%	4/1/2008	4/1/2013	(2,074)
$50,000	3.100%	10/10/2008	10/10/2013	(2,443)
$50,000	3.090%	10/10/2008	10/10/2013	(2,431)
$50,000	2.295%	12/18/2008	12/18/2013	(1,323)
Total Fair Market Value of interest rate derivatives				$(12,307)

(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 three months ended March 31, 2011 and year ended December 31, 2010.

	March 31, 2011	December 31, 2010
	(In thousands)	
Asset retirement obligation - beginning of period	$111,262	$84,917
Liabilities incurred with properties acquired	1,438	17,618
Liabilities incurred with properties drilled	—	631
Liabilities settled during the period	(806)	(1,993)
Current period accretion	1,058	3,472
Current period revisions to previous estimates	(848)	6,617
Asset retirement obligation - end of period	$112,104	$111,262

(9) Earnings Per Unit

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

	Three Months Ended March 31, 2011	2010
	(In thousands)	
Income (loss) available to unitholders	$(60,370)	$10,220
Weighted average number of units outstanding	43,529	39,216
Effect of dilutive securities:		
Restricted units	—	3
Weighted average units and potential units outstanding	43,529	39,219
Basic and diluted earnings (loss) per unit	$(1.39)	$0.26

For the three months ended March 31, 2011, 81,203 restricted units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect.

(10) Unit-Based Compensation

Long-Term Incentive Plan

On March 15, 2006, a Long-Term Incentive Plan (“LTIP”) for Legacy was created 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 March 31, 2011 grants of awards net of forfeitures covering 1,441,708 units had been made, comprised of 266,014 unit option awards, 650,301 unit appreciation rights awards ("UARs"), 146,319 restricted unit awards, 323,031 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. However, ASC 718 stipulates that “if an entity that nominally has the choice of settling awards by issuing stock predominately settles in cash, or if the entity usually settles in cash whenever an employee asks for cash settlement, the entity is settling a substantive liability rather than repurchasing an equity instrument.” Due to Legacy's historical practice of settling unit options, UARs and phantom unit awards in cash, Legacy accounts for unit options, UARs, and phantom unit awards by utilizing the liability method as described in ASC 718. The liability method requires companies to measure the cost of the employee services in exchange for a cash award based on the fair value of the underlying security at the end of the period. Compensation cost is recognized based on the change in the liability between periods.

Unit Appreciation Rights and Unit Options

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

During the year ended December 31, 2010, Legacy issued 75,500 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 three-month period ended March 31, 2011, Legacy issued 7,500 UARs to employees which vest ratably over a three-year period. All UARs granted in 2010 and 2011 expire seven years from the grant date and are exercisable when they vest.

For the three-month periods ended March 31, 2011 and 2010, Legacy recorded \$0.9 million and \$0.6 million, respectively, of compensation expense due to the change in liability from December 31, 2010 and 2009, respectively, based on its use of the Black-Scholes model to estimate the March 31, 2011 and 2010 fair value of these unit options and UARs (see Note 6). As of March 31, 2011, there was a total of approximately \$2.3 million of unrecognized compensation costs related to the unexercised and non-vested portion of these UARs. At March 31, 2011, this cost was expected to be recognized over a weighted-average period of approximately 1.9 years. Compensation expense is based upon the fair value as of March 31, 2011 and is recognized as a percentage of the service period satisfied. Since Legacy's trading history does not yet match the term of the outstanding unit option and UAR awards, it has used an estimated volatility factor of approximately 50% 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 March 31, 2011 fair value to be realized as compensation cost based on the percentage of service period satisfied. Based on historical data, Legacy has assumed an estimated forfeiture rate of 2.8%. As required by ASC 718, Legacy will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.10 per unit.

A summary of option and UAR activity for the three months ended March 31, 2011 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2011	614,338	$ 21.40		
Granted	7,500	29.15		
Exercised	(31,334)	24.49		
Forfeited	(13,500)	21.08		
Outstanding at March 31, 2011	577,004	$ 21.34	4.09	$5,769,955
Options and UARs exercisable at March 31, 2011	152,500	$ 22.71	1.59	$1,315,455

The following table summarizes the status of Legacy's non-vested UARs since January 1, 2011:

	Non-Vested UARs	
	Number of Units	Weighted-Average Exercise Price
Non-vested at January 1, 2011	445,669	$ 20.64
Granted	7,500	29.15
Vested - Unexercised	(14,665)	19.22
Vested - Exercised	(500)	10.20
Forfeited	(13,500)	21.08
Non-vested at March 31, 2011	424,504	$ 20.84

Legacy has used a weighted-average risk-free interest rate of 1.7% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at March 31, 2011 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.

	Three Months Ended March 31, 2011
Expected life (years)	4.09
Annual interest rate	1.7 %
Annual distribution rate per unit	$2.10
Volatility	50 %

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 May 31, 2010, Legacy granted 10,000 phantom units to an employee which would have vested ratably over a five-year period, beginning at the date of grant. However, these units were forfeited upon the resignation of the employee prior to the first vesting date. 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") which accumulate and accrue based on the total number of actual amounts vested and will be payable at the date of vesting.

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 were 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 0% to 25% of the amount will vest, depending upon the Legacy TUR ranking among its peer group) to more than 20% (where 50% to 100% of the amount will vest, depending upon the Legacy TUR ranking among its 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 Adjusted Alerian MLP Index increases. The applicable Legacy TUR range is from less than 8% (where 0% to 30% of the amount will vest, depending upon the Legacy TUR percentile ranking among the Adjusted Alerian MLP Index) to more than 20% (where 50% to 100% of the amount will vest, depending upon the Legacy TUR percentile ranking among the Adjusted 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. On

February 18, 2011, the Compensation Committee approved the award of 32,806 subjective, or service-based, phantom units and 53,487 objective, or performance based, phantom units to Legacy's five executive officers.

Compensation expense related to the phantom units and associated DERs was \$0.8 million and \$0.4 million for the three months ended March 31, 2011 and 2010, respectively.

Restricted Units

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 \$0.2 million and \$0.01 million for the three months ended March 31, 2011 and 2010, respectively. As of March 31, 2011, there was a total of \$1.3 million of unrecognized compensation expense related to the non-vested portion of these restricted units. At March 31, 2011, this cost was expected to be recognized over a weighted-average period of 2.0 years. Pursuant to the provisions of ASC 718, Legacy’s issued units, as reflected in the accompanying consolidated balance sheet at March 31, 2011, do not include 81,203 units related to unvested restricted unit awards.

Board Units

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) Subsidiary Guarantors

Legacy is currently contemplating the filing of an automatic registration statement on Form S-3 during May of 2011. Securities that may be registered include debt securities which may be guaranteed by Legacy's subsidiaries and are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933. Legacy, as the parent company, has no independent assets or operations. Legacy contemplates that if it offers guaranteed debt securities pursuant to the registration statement, all guarantees will be full and unconditional and joint and several, and any subsidiaries of Legacy other than the subsidiary guarantors will be minor. In addition, there are no restrictions on the ability of Legacy to obtain funds from its subsidiaries by dividend or loan.

(12) Subsequent Events

On April 20, 2011, Legacy’s board of directors approved a distribution of $0.53 per unit payable on May 13, 2011 to unitholders of record on May 2, 2011.

On April 15, 2011, the Eleventh Court of Appeals, in an appeal styled Raven Resources, LLC, Appellant v. Legacy Reserves Operating, LP, Appellee, on appeal from the 385th District Court, Midland County, Texas, reversed and rendered in part and reversed and remanded in part the trial court's summary judgement, dated November 10, 2009, in favor of Legacy Reserves Operating, LP ("LROLP"), a subsidiary of Legacy Reserves, LP.

In its original petition to the trial court, filed August 15, 2008, Raven Resources, LLC ("Raven") had sought, among other things, a declaratory judgment that the purchase agreement dated July 11, 2007 (the "PSA") providing for the purchase by LROLP of various non-operated oil and natural gas properties and interests primarily in the Permian Basin for $20.3 million, subject to adjustment, was void, as a matter of law, alleging an employee of Raven had forged the signature of David Stewart, Raven's managing member. Raven also asked the trial court to rescind the transaction, and to account for all proceeds received by LROLP since the properties were originally conveyed. Further, Raven alleged that LROLP had failed to pay the full purchase price for the properties as David Stewart had allegedly only been aware of a June 27, 2007 draft of a purchase agreement, which provided for a $26.6 million purchase price, whereas the PSA, following property due diligence, contained a reduced purchase price of $20.3 million. Raven alleged that David Stewart, despite having signed 35 assignments incorporating the PSA as well as a certificate acknowledging Mr. Stewart had executed the PSA, was not aware of the revised terms of the PSA, nor the amounts of payments made to Raven until August 27, 2007, when Mr. Stewart purportedly discovered the employee's fraud. With the proceeds received from Legacy at the closing of the transaction on August 3, 2007, Raven had paid its debts and its partners. In addition, Raven alleged that LROLP benefitted from the fraud promulgated by Michael Lee, and asked the trial court for damages in excess of $6 million. Raven does not claim that Legacy knew about the forgery.

LROLP filed a counterclaim for declaratory relief and for money damages based upon indemnity obligations and post-closing adjustments. The trial court granted a partial summary judgment in favor of LROLP, denied a partial summary judgment sought by Raven, and entered a take-nothing judgment against Raven. The trial court severed the counterclaims brought by LROLP.

In its April 15, 2011 ruling, the Court of Appeals rendered judgment that the PSA was void, as a matter of law, and that a void instrument is not subject to ratification. Further, while the Appeals Court held that the incorporation of the PSA into the assignments for the transfer of the properties will not void the assignments, the assignments were not complete in and of themselves in the absence of the terms of the PSA. The Court of Appeals further remanded to the trial court any issues regarding the repayment of the funds advanced by LROLP, as well as any issues regarding any consideration received by LROLP from or related to the properties.

Legacy intends to pursue all available legal options regarding the further appeal of this ruling, including the filing of a motion of re-hearing with the Court of Appeals. At this time, Legacy cannot predict the Court of Appeals' or any other court's action, or the eventual outcome of this matter. Therefore, any liability that might arise as a result of this matter is not probable or estimable at this time. Legacy currently believes that any outcome, which may include no payment, the unwinding of the transaction (which Legacy expects would have an effect of less than $6 million) or a payment of approximately $6 million to Raven, will not have a material impact on its financial condition or ability to make cash distributions at expected levels, though it could have a material adverse effect on its net income (loss).

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, 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 COG and Wyoming acquisitions have been included from December 22, 2010 and February 17, 2010, respectively.

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 (CO2 and nitrogen) 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, obtain regulatory approvals and contract drilling rigs and personnel.

Our revenues are highly sensitive to changes in oil and natural gas prices and to levels of production. As set forth under “Cash Flow from Operations” below, we have entered into oil and natural gas derivatives designed to mitigate the effects of price fluctuations covering a significant portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. We 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. We do not consider royalties paid to mineral owners an expense as we deduct hydrocarbon volumes owned by mineral owners from the reported hydrocarbon sales volumes.

Operating Data

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

	Three Months Ended March 31, 2011	2010
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$59,265	$37,748
Natural gas liquid sales	4,250	3,750
Natural gas sales	9,253	8,169
Total revenue	$72,768	$49,667
Expenses:		
Oil and natural gas production	$21,497	$14,156
Ad valorem taxes	$2,260	$914
Total oil and natural gas production	$23,757	$15,070
Production and other taxes	$4,357	$2,919
General and administrative	$6,358	$4,761
Depletion, depreciation, amortization and accretion	$19,560	$13,115
Realized commodity derivative settlements		
Realized gain (loss) on oil derivatives	$(1,140)	$2,907
Realized loss on natural gas liquid derivatives	$—	$(39)
Realized gain on natural gas derivatives	$2,816	$1,921
Production:		
Oil - MBbls	676	504
Natural gas liquids - Mgals	3,317	3,457
Natural gas - MMcf	1,601	1,216
Total (MBoe)	1,022	789
Average daily production (Boe/d)	11,356	8,767
Average sales price per unit (excluding derivatives):		
Oil price per barrel	$87.67	$74.90
Natural gas liquid price per gallon	$1.28	$1.08
Natural gas price per Mcf	$5.78	$6.72
Combined (per Boe)	$71.20	$62.95
Average sales price per unit (including realized derivative gains/losses):		
Oil price per barrel	$85.98	$80.66
Natural gas liquid price per gallon	$1.28	$1.07
Natural gas price per Mcf	$7.54	$8.30
Combined (per Boe)	$72.84	$69.02
NYMEX oil index prices per barrel:		
Beginning of Period	$91.38	$79.36
End of Period	$106.72	$83.76
NYMEX gas index prices per Mcf:		
Beginning of Period	$4.41	$5.57
End of Period	$4.39	$3.87

Average unit costs per Boe:		
Oil and natural gas production	$21.03	$17.94
Ad valorem taxes	$2.21	$1.16
Production and other taxes	$4.26	$3.70
General and administrative	$6.22	$6.03
Depletion, depreciation, amortization and accretion	$19.14	$16.62

Results of Operations

Three-Month Period Ended March 31, 2011 Compared to Three-Month Period Ended March 31, 2010

Legacy's revenues from the sale of oil were $59.3 million and $37.7 million for the three-month periods ended March 31, 2011 and 2010, respectively. Legacy's revenues from the sale of NGLs were $4.3 million and $3.8 million for the three-month periods ended March 31, 2011 and 2010, respectively. Legacy's revenues from the sale of natural gas were $9.3 million and $8.2 million for the three-month periods ended March 31, 2011 and 2010, respectively. The $21.5 million increase in oil revenues reflects the increase in average realized price of $12.77 per Bbl (17%) as well as an increase in oil production of 172 MBbls (34%) due primarily to Legacy's purchase of additional oil and natural gas properties, including the COG Acquisition. The increase in oil production is also due to a full quarter of production from the Wyoming Acquisition compared to a partial quarter of production during the period ended March 31, 2010, as the Wyoming Acquisition closed on February 17, 2010. The $0.5 million increase in proceeds from NGL sales reflects the increase in average realized price of $0.20 per gallon (19%) partially offset by the decrease in NGL production of approximately 140 MGals (4%) due primarily to 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 $1.1 million increase in natural gas revenues reflects the increase in natural gas production of approximately 385 MMcf (32%) due primarily to Legacy's purchase of additional oil and natural gas properties, including the COG Acquisition. These increases in natural gas production were partially offset by a decrease in average realized natural gas prices of $0.94 per Mcf (14%).

For the three-month period ended March 31, 2011, Legacy recorded $75.5 million of net losses on oil and natural gas derivatives comprised of realized gains of $1.7 million from net cash settlements of oil and natural gas derivative contracts and a net unrealized loss of $77.1 million. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives that will be settled in future periods. Legacy had unrealized net losses from oil derivatives because oil futures prices increased during the three-month period ended March 31, 2011. NYMEX oil futures prices at March 31, 2011 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 liability attributable to unrealized net losses from Legacy's outstanding oil derivatives increased, resulting in an unrealized net loss of $74.1 million for the quarter. Legacy had unrealized net losses from natural gas derivatives because the NYMEX natural gas futures prices for periods beyond the spot price increased during the three-month period ended March 31, 2011. Due to this increase in natural gas prices during the quarter, the positive differential between Legacy's fixed price natural gas derivatives and NYMEX prices decreased. Accordingly, the net asset attributable to unrealized net gains from Legacy's outstanding natural gas derivatives decreased, resulting in unrealized net losses of $3.0 million for the quarter. For the three-month period ended March 31, 2010, Legacy recorded $11.9 million of net gains on oil, NGL and natural gas derivatives, comprised of realized gains of $4.8 million from net cash settlements of oil, NGL and natural gas derivative contracts and a net unrealized gain of $7.1 million on oil, NGL and natural gas derivative contracts.

Legacy's oil and natural gas production expenses, excluding ad valorem taxes, increased to $21.5 million ($21.03 per Boe) for the three-month period ended March 31, 2011, from $14.2 million ($17.94 per Boe) for the three-month period ended March 31, 2010. Production expenses increased primarily due to industry-wide increases in costs of services and certain operating costs due to a higher level of industry activity caused by higher oil prices. In addition, oil and natural gas production expenses increased due to increased workover activity of $0.4 million, the purchases of oil and natural gas properties, including approximately $2.4 million of expense related to the COG Acquisition and $2.1 million of increased expenses related to the Wyoming Acquisition, which closed on February 17, 2010. Legacy's ad valorem tax expense increased to $2.3 million ($2.21 per Boe) for the three-month period ended March 31, 2011, from $0.9 million ($1.16 per Boe) for the three-month period ended March 31, 2010 primarily due to $0.7 million of ad valorem tax expenses related to the COG and Wyoming Acquisitions, increased property values directly related to higher commodity prices, and a lower accrual of ad valorem taxes during the three months ended March 31, 2010 related to lower than expected ad valorem taxes during 2009.

Legacy’s production and other taxes were $4.4 million and $2.9 million for the three-month periods ended March 31, 2011 and 2010, respectively. Production and other taxes increased primarily because of higher realized commodity prices and production volumes, as production and other taxes as a percentage of revenue remained largely unchanged.

Legacy’s general and administrative expenses were $6.4 million and $4.8 million for the three-month periods ended March 31, 2011 and 2010, respectively. General and administrative expenses increased primarily due to a $0.9 million increase in non-cash LTIP expenses related to increased unit prices, $0.2 million in costs related to an accounting system implementation and increased salary expense related to the hiring of additional employees primarily in Wyoming.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $19.6 million and $13.1 million for the three-month periods ended March 31, 2011 and 2010, respectively. DD&A increased primarily because of increased production from our development activity and recent acquisitions, including the COG and Wyoming Acquisitions, and proportionate increases in cost basis. These increases were partially offset by increased reserve volumes related to our development activities, acquisitions and higher average commodity prices.

Impairment expense was $1.0 million and $7.9 million for the three-month periods ended March 31, 2011 and 2010, respectively. In the three-month period ended March 31, 2011, Legacy recognized impairment expense on three separate producing fields primarily related to reserve valuation adjustments on fields acquired in the COG Acquisition between the acquisition date and the period ended March 31, 2011. Impairment expense for the period ended March 31, 2010, was related to the decrease in natural gas prices during the period which reduced the expected future net cash flows on 44 separate producing fields below the cost basis for the respective fields.

Legacy recorded interest expense of $3.4 million and $7.3 million for the three-month periods ended March 31, 2011 and 2010, respectively. Interest expense decreased approximately $3.9 million due primarily to favorable mark-to-market adjustments of our interest rate swap derivatives of $1.7 million for the three month period ended March 31, 2011, compared to interest expense of $3.2 million related to mark-to-market adjustments for the three month period ended March 31, 2010.

Non-GAAP Financial Measures

For the three months ended March 31, 2011 and 2010, respectively, Adjusted EBITDA increased 29% to $42.3 million from $32.7 million primarily due to increased revenues from our oil, NGL and natural gas sales in the three months ended March 31, 2011 compared to the three months ended March 31, 2010, partially offset by higher production and other expenses. These increased revenues more than offset the decreased realized commodity derivative settlements of approximately $3.1 million from $4.8 million to $1.7 million for the three months ended March 31, 2010 and 2011, respectively. For the three months ended March 31, 2011 and 2010, respectively, Distributable Cash Flow increased 7% to $23.6 million from $22.1 million as increases in Adjusted EBITDA more than offset increases in development capital expenditures. Due to favorable commodity prices and greater availability of both drilling rigs and oilfield services, Legacy increased development capital expenditures for the three months ended March 31, 2011 to $11.9 million from $5.2 million for the three months ended March 31, 2010.

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 months ended March 31, 2011 and 2010, respectively.

	Three Months Ended March 31,	
	2011	2010
	(dollars in thousands)	
Net income (loss)	$(60,370)	$10,220
Plus:		
Interest expense	3,377	7,333
Income tax expense (benefit)	(330)	173
Depletion, depreciation, amortization and accretion	19,560	13,115
Impairment of long-lived assets	1,047	7,916
Equity in income of partnership	(29)	(23)
Unit-based compensation expense	1,910	1,022
Unrealized (gain)/loss on oil and natural gas derivatives	77,132	(7,072)
Adjusted EBITDA	$42,297	$32,684
Less:		
Cash interest expense	4,545	3,703
Cash settlements of LTIP unit awards	2,285	1,702
Development capital expenditures	11,909	5,202
Distributable Cash Flow	$23,558	$22,077

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, its Initial Public Offering in January 2007 and its public equity offerings in September 2009, January 2010 and November 2010. To date, Legacy's primary uses of capital have 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 revolving 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 $1.7 million and $4.8 million of cash settlements during the three months ended March 31, 2011 and 2010, respectively. Based upon current oil and natural gas price expectations and our extensive commodity derivatives positions for the year ending December 31, 2011, 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 $500.0 million. As of May 5, 2011, we had $99.9 million available for borrowing under our revolving credit facility. Based on their commodity price expectations, our lenders redetermine the borrowing base semi-annually, with the next redetermination scheduled for October 2011. Please read "— Financing Activities — Our Revolving Credit Facility."

Cash Flow from Operations

Legacy's net cash provided by operating activities was $34.4 million and $23.3 million for the three-month periods ended March 31, 2011 and 2010, respectively. The 2011 period was favorably impacted by higher commodity prices and production volumes, which were partially offset by higher expenses. In addition, the net cash amount for 2011 and 2010 does not include cash settlements received of $1.7 million and $4.8 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 $24.0 million for the three-month period ended March 31, 2011. The total includes $12.1 million for the acquisition of oil and natural gas properties in six individually immaterial acquisitions and $11.9 million of development projects. Legacy's cash capital expenditures were $131.5 million for the three-month period ended March 31, 2010. The total includes $126.3 million for the acquisition of oil and natural gas properties in the Wyoming acquisition and two individually immaterial acquisitions and $5.2 million of development projects.

Our capital expenditure budget, which predominantly consists of drilling, recompletion and capital workover projects, is currently $52.0 million for the year ending December 31, 2011, of which $11.9 million has been completed during the three-months ended March 31, 2011. Our remaining borrowing capacity under our revolving credit facility is $99.9 million as of May 5, 2011. 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, 2011, 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 $40.1 million. Future cash distributions will be at levels to be determined based on cash available for distribution, any remaining borrowing capacity for cash distributions under our credit facility, requirements to repay debt and any other factors the board of directors of our general partner may consider. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

We enter into oil and natural gas derivative transactions to reduce the impact of oil and natural gas price volatility on our operations. Currently, we use derivatives to offset price volatility on NYMEX oil and natural gas prices, which do not include the additional net discount that we typically experience in the Permian Basin. For the three-month period ended March 31, 2011 and 2010 we had favorable cash settlements of $1.7 million and $4.8 million, respectively, related to our commodity derivative settlements. At March 31, 2011, we had in place oil and natural gas derivatives covering significant portions of our estimated 2011 through 2015 oil, NGL and natural gas production. As of May 5, 2011, we have derivative contracts covering approximately 69% of our remaining expected oil, NGL and natural gas production for 2011. As of May 5, 2011, we also have derivative contracts covering approximately 38% of our currently expected oil and natural gas production for 2012 through 2015.

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

May 5, 2011, covering the period from April 1, 2011 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 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
April - December 2011(a)	1,659,001	$89.09	$67.33 - $140.00
2012(a)	1,511,121	$83.05	$67.72 - $109.20
2013(a)	1,051,243	$84.73	$80.10 - $90.50
2014	513,514	$88.68	$87.50 - $90.50
2015	145,051	$90.50	$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 paid to us in the form of 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. These additional potential volumes are not reflected in the above table.

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
April - December 2011	4,972,462	$5.77	$4.15 - $8.70
2012	4,406,990	$6.21	$4.72 - $8.70
2013	3,270,254	$5.72	$5.00 - $6.89
2014	1,749,104	$5.76	$5.40 - $6.47
2015	1,020,000	$5.80	$5.79 - $5.82

On June 24, 2008, we entered into a NYMEX West Texas Intermediate crude oil derivative collar contract that combines a long put option or “floor” with a short call option or “ceiling.” The following table summarizes the oil collar contract currently in place as of May 5, 2011, covering the period from April 1, 2011 through December 31, 2012:

Calendar Year	Volumes (Bbls)	Floor Price	Ceiling Price
April - December 2011	51,400	$120.00	$156.30
2012	65,100	$120.00	$156.30

On January 12, 2011, we entered into a West Texas Waha natural gas derivative collar contract that combines a long put option or "floor" with a short call option or "ceiling." The following table summarizes the natural gas collar contract currently in place as of May 5, 2011, covering the period from January 1, 2012 through December 31, 2012:

Calendar Year	Volumes (Bbls)	Floor Price	Ceiling Price
2012	360,000	$4.00	$5.45

We have entered into multiple NYMEX West Texas Intermediate crude oil derivative three-way collar contracts. Each contract combines a long put, a short put and a short call. The use of the long put combined with the short put allows us to sell a call at a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk 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. In regards to our three-way collar contracts, if the market price has fallen below the short put fixed price, we would receive the market price plus $25 or $30 per barrel, depending on the contract. The following table summarizes the three-way oil collar contracts currently in place as of May 5, 2011, covering the period from January 1, 2012 through December 31, 2015:

Calendar Year	Volumes (Bbls)	Average Short Put	Average Long Put	Average Short Call
2012	329,400	$67.50	$93.33	$112.65
2013	452,870	$63.02	$88.63	$110.19
2014	536,880	$62.55	$88.06	$115.55
2015	514,050	$63.20	$88.20	$119.18

Financing Activities

Legacy's net cash used in financing activities was $13.6 million for the three months ended March 31, 2011, compared to cash provided of $99.5 million for the three months ended March 31, 2010. During the three months ended March 31, 2011, total net borrowings under our revolving credit facility were $14.0 million, comprised of borrowings of $55.0 million and repayments of $41.0 million. Offsetting the net cash proceeds from net borrowings during the three months ended March 31, 2011, was cash used in the amount of $22.9 million for distributions to unitholders and $4.7 million of cash paid related to entering into the Current Credit Agreement (defined below). Cash used in financing activities during the three months ended March 31, 2010, included $27.0 million in net borrowings under our revolving credit facility and $95.4 million in cash proceeds from our January 2010 public equity offering partially offset by $20.8 million for distributions to unitholders.

Our Revolving Credit Facility

Previous Credit Agreement

On March 27, 2009, we entered into a three-year, $600 million secured revolving credit facility (the "Previous Credit Agreement") and retained BNP Paribas as administrative agent to replace our initial four-year, $300 million revolving credit facility with BNP Paribas as administrative agent. All borrowings outstanding under the Previous Credit Agreement were paid off in full on March 10, 2011 with borrowings under the Current Credit Agreement.

Current Credit Agreement

On March 10, 2011, we entered into an amended and restated five-year, $1 billion secured revolving credit facility with BNP Paribas as administrative agent (the "Current Credit Agreement"). Our obligations under the Current Credit Agreement are secured by mortgages on 80% of our oil and natural gas properties as well as a pledge of all of our ownership interests in our operating subsidiaries. Borrowings under the Current Credit Agreement mature on March 10, 2016. The amount available for borrowing at any one time is limited to the borrowing base, currently at $500 million, with a $2 million sub-limit for letters of credit. The borrowing base is subject to semi-annual redeterminations on or about April 1 and October 1 of each year, commencing on October 1, 2011. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. We also have the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of certain oil and natural gas properties where the purchase price is greater than 10% of the borrowing base. Any increase in the borrowing base requires the consent of all the lenders and any decrease in or maintenance of the borrowing base must be approved by the lenders holding at least 66.67% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility. If the required lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66.67% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility, so long as it does not increase the borrowing base then in effect. Outstanding borrowings in excess of the borrowing base must be prepaid, and, if mortgaged properties represent less than 80% of total value of oil and gas properties evaluated in the most recent reserve report, we must pledge other oil and natural gas properties as additional collateral. Legacy may at any time issue up to $500 million in aggregate principal amount of senior notes or new debt whose proceeds are used to refinance such senior notes, subject to specified conditions in the Current Credit Agreement, which include that upon the issuance of such senior notes or new debt, the borrowing base shall be reduced by an amount equal to (i) in the case of senior notes, 25% of the stated principal amount of the senior notes and (ii) in the case of new debt, 25% of the portion of the new debt that exceeds the principal amount of the senior notes. Also, notwithstanding that a lender (or its affiliate) is no longer a party to the Current Credit Agreement, any lender (or its affiliate) which has entered into any hedging arrangement with us while a party to the Current 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 Current Credit Agreement, the related loan documents and our hedging arrangements.

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

- with respect to ABR loans, the alternate base rate equals the highest of the prime rate, the Federal funds effective rate plus 0.50%, the one-month London interbank rate (“LIBOR”) plus 1.00%, plus an applicable margin ranging from and including 0.75% and 1.75% per annum, determined by the percentage of the borrowing base then in effect that is drawn, or
- with respect to any Eurodollar loans, one-, two-, three- or six-month LIBOR plus an applicable margin ranging from and including 1.75% and 2.75% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

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

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

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

- total debt as of the last day of the most recent quarter to EBITDA in total over the last four quarters of not more than 4.0 to 1.0; and
- consolidated current assets, as of the last day of the most recent quarter and including the unused amount of the total commitments, to consolidated current liabilities as of the last day of the most recent quarter of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC 815, which includes the current portion of oil, natural gas derivatives and interest rate swaps.

Interest expense, as defined in the Current 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 $2.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;

- bankruptcy or insolvency events involving us or any of our subsidiaries;

- the loan documents cease to be in full force and effect;

- our failing to create a valid lien, except in limited circumstances;

- a change of control, which will occur upon (i) the acquisition by any person or group of persons of beneficial ownership of more than 35% of the aggregate ordinary voting power of our equity securities, (ii) the first day on which a majority of the members of the board of directors of our general partner are not continuing directors (which is generally defined to mean members of our board of directors as of March 10, 2011 and persons who are nominated for election or elected to our general partner's board of directors with the approval of a majority of the continuing directors who were members of such board of directors at the time of such nomination or election), (iii) the direct or indirect sale, transfer or other disposition in one or a series of related transactions of all or substantially all of the properties or assets (including equity interests of subsidiaries) of us and our subsidiaries to any person, (iv) the adoption of a plan related to our liquidation or dissolution or (v) Legacy Reserves GP, LLC ceasing to be our sole general partner;

- the entry of, and failure to pay, one or more adverse judgments in excess of $2.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and

- specified ERISA events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.0 million in any year.

As of March 31, 2011, Legacy was in compliance with all financial and other covenants of the revolving credit facility.

Legacy periodically enters into interest rate swap transactions to mitigate the volatility of interest rates. As of March 31, 2011, Legacy had interest rate swaps outstanding through December of 2013 on $264 million of floating rate debt to a weighted-average fixed rate of 3.05%.

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, 2010 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 three-month period ended March 31, 2011 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, The Bank of Nova Scotia and Credit Agricole). Our existing oil, NGL, natural gas derivatives and interest rate swaps 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 December, 2010, the FASB issued ASU 2010-29, Business Combinations (Topic 805) Disclosure of Supplementary Pro Forma Information for Business Combinations, which addresses the diversity in practice regarding the interpretation of the pro forma revenue and earnings disclosure requirements for business combinations. The amended guidance specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Additionally, the amended guidance expands the supplemental pro forma disclosures under Topic 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings.
The amended guidance is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010, which is the Partnership's fiscal period beginning January 1, 2011. Early adoption is permitted. Legacy adopted the amended guidance on January 1, 2011, the adoption of which did not impact Legacy's results of operations, cash flows or financial position as this guidance provides only disclosure requirements.

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, collars, three-way collars and swaptions. These derivative transactions are intended to support oil, NGL and natural gas prices at targeted levels and to manage our exposure to oil, NGL and natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

As of March 31, 2011, the fair market value of Legacy's commodity derivative positions was a net liability of $91.8 million based on NYMEX futures prices from April 2011 to December 2015 for both oil and natural gas. As of December 31, 2010, the fair market value of Legacy's commodity derivative positions was a net liability of $14.7 million based on NYMEX futures prices from January 2011 to December 2015 for both oil and natural gas. The futures market prices of both oil and natural gas increased from December 31, 2010 to March 31, 2011 across the overlapping periods of the time frames referenced above over which our commodity derivatives are in place. For more discussion about our derivative transactions and to see a table listing the oil and natural gas derivatives from April 2011 through December 31, 2015, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations— Investing Activities."

Interest Rate Risks

At March 31, 2011, Legacy had debt outstanding of $339 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by Legacy for the three-month period ended March 31, 2011 was 3.3%. A 1% increase in LIBOR on Legacy's outstanding debt as of March 31, 2011 would result in an estimated $0.75 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 March 31, 2011. 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.

Effective January 1, 2011, we implemented a new accounting system in conjunction with a transition to bring our back-office accounting functions in-house from an outsourced third-party. While these transitions have changed the physical location within the accounting process where certain internal control points occur, the nature and extent of such internal controls remain unchanged. Therefore, there have been no changes in our internal control over financial reporting that occurred during our fiscal quarter ended March 31, 2011, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, except as discussed in Note 12 in the Notes to the Condensed Consolidated Financial Statements, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Item 1A. Risk Factors.

In addition to the 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, 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 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)
10.1	Second Amended and Restated Credit Agreement dated as of March 10, 2011 (Incorporated by reference to Legacy Reserves LP's Current Report on Form 8-K (File No. 001-33249) filed March 17, 2011, Exhibit 10.1)
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

May 6, 2011

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