BERRY PETROLEUM CO
Form 10-Q
October 27, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended September 30, 2010

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from to

Commission file number 1-9735

BERRY PETROLEUM COMPANY

(Exact name of registrant as specified in its charter)

DELAWARE	**77-0079387**
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

1999 Broadway, Suite 3700

Denver, Colorado 80202

(Address of principal executive offices, including zip code)

Registrant s telephone number, including area code: **(303) 999-4400**

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. YES x NO o

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 x NO o

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 definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

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

As of October 15, 2010 the registrant had 53,032,471 shares of Class A Common Stock ($.01 par value) outstanding. The registrant also had 1,797,784 shares of Class B Stock ($.01 par value) outstanding on October 15, 2010 all of which is held by an affiliate of the registrant.

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BERRY PETROLEUM COMPANY

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September 30, 2010

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BERRY PETROLEUM COMPANY

Condensed Balance Sheets

(Unaudited)

(In Thousands, Except Share Information)

	September 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 54	$ 5,311
Short-term investments	65	66
Accounts receivable, net of allowance for doubtful accounts of $0 and $38,508, respectively	84,502	74,337
Deferred income taxes	11,882	5,623
Derivative instruments	5,414	11,527
Prepaid expenses and other	14,854	6,612
Total current assets	116,771	103,476
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,409,225	2,106,385
Derivative instruments	3,082	735
Other assets	24,804	29,539
	$ 2,553,882	$ 2,240,135
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 94,756	$ 63,096
Revenue and royalties payable	28,160	25,878
Accrued liabilities	46,075	29,320
Derivative instruments	44,910	33,843
Total current liabilities	213,901	152,137
Long-term liabilities:		
Deferred income taxes	319,279	237,161
Senior secured revolving credit facility	240,000	372,000
8.25% Senior subordinated notes due 2016	200,000	200,000
10.25% Senior notes due 2014, net of unamortized discount of $11,666 and $13,456, respectively	438,334	436,544
Asset retirement obligation	51,161	43,487
Other long-term liabilities	18,386	19,711
Derivative instruments	32,566	75,836
	1,299,726	1,384,739
Shareholders equity:		
Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding		
Capital stock, $.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 53,009,221 and 42,952,499 shares issued and outstanding, respectively	512	430
Class B Stock, 3,000,000 shares authorized;1,797,784 shares issued and outstanding (liquidation preference of $899)	18	18
Capital in excess of par value	322,600	89,068
Accumulated other comprehensive loss	(48,533)	(60,372)
Retained earnings	765,658	674,115
Total shareholders equity	1,040,255	703,259
	$ 2,553,882	$ 2,240,135

The accompanying notes are an integral part of these condensed financial statements.

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BERRY PETROLEUM COMPANY

Condensed Statements of Income (Loss)

(Unaudited)

(In Thousands, Except Per Share Data)

	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010	Nine months ended September 30, 2009
REVENUES AND OTHER INCOME ITEMS				
Sales of oil and gas	$ 151,671	$ 127,455	$ 451,003	$ 374,117
Sales of electricity	9,451	9,137	27,313	26,032
Gas marketing	4,918	5,217	18,194	17,646
Realized and unrealized (loss) gain on derivatives, net	(27,178)	531	30,482	6,565
Settlement of Flying J bankruptcy claim			21,992	
Gain on sale of assets		828		828
Interest and other income, net	362	287	2,320	1,375
	139,224	143,455	551,304	426,563
EXPENSES				
Operating costs - oil and gas production	46,782	39,195	140,269	111,317
Operating costs - electricity generation	7,220	6,892	24,729	22,071
Production taxes	6,215	3,874	16,484	14,411
Depreciation, depletion & amortization - oil and gas production	49,367	33,502	128,976	104,271
Depreciation, depletion & amortization - electricity generation	819	951	2,407	2,938
Gas marketing	4,067	4,633	16,209	16,149
General and administrative	12,399	10,686	38,389	37,143
Interest	15,586	14,562	49,373	35,201
Extinguishment of debt		329		10,823
Transaction costs on acquisitions			2,635	
Dry hole, abandonment, impairment and exploration	586	69	2,221	209
Bad debt recovery			(38,508)	
	143,041	114,693	383,184	354,533
Income (loss) before income taxes	(3,817)	28,762	168,120	72,030
Income tax (benefit) provision	(794)	10,423	64,450	24,681
Income (loss) from continuing operations	(3,023)	18,339	103,670	47,349
Income (loss) from discontinued operations, net of taxes		668		(6,323)
Net income (loss)	$ (3,023)	$ 19,007	$ 103,670	$ 41,026
Basic net (loss) income from continuing operations per share	$ (0.06)	$ 0.41	$ 1.94	$ 1.04
Basic net income (loss) from discontinued operations per share	$	$ 0.01	$	$ (0.14)
Basic net (loss) income per share	$ (0.06)	$ 0.42	$ 1.94	$ 0.90
Diluted net (loss) income from continuing operations per share	$ (0.06)	$ 0.40	$ 1.93	$ 1.03

Diluted net income (loss) from discontinued operations per share	$		$	0.01	$		$	(0.14)
Diluted net (loss) income per share	$	(0.06)	$	0.41	$	1.93	$	0.89
Dividends per share	$	0.075	$	0.075	$	0.225	$	0.225

The accompanying notes are an integral part of these condensed financial statements.

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BERRY PETROLEUM COMPANY

Condensed Statements of Cash Flows

(Unaudited)

(In Thousands)

	Nine months ended September 30, 2010	2009
Cash flows from operating activities:		
Net income	$ 103,670	$ 41,026
Depreciation, depletion and amortization	131,383	109,397
Extinguishment of debt		10,823
Amortization of debt issue costs and net discount	6,383	4,891
Dry hole and impairment	1,477	9,643
Unrealized (gain) loss on derivatives	(8,999)	4,796
Stock-based compensation expense	7,134	7,054
Deferred income taxes	67,533	13,546
Loss on sale of oil and natural gas properties		79
Other, net		(5,253)
Cash paid for abandonment	(1,830)	(293)
Bad debt recovery	(38,508)	
Change in book overdraft	8,309	(20,199)
Decrease (increase) in current assets other than cash and cash equivalents	19,852	(9,828)
Increase (decrease) in current liabilities other than book overdraft and line of credit	22,117	(17,303)
Net cash provided by operating activities	318,521	148,379
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(230,955)	(94,636)
Property acquisitions	(154,517)	(11,904)
Capitalized interest	(20,402)	(21,145)
Proceeds from sale of assets		139,796
Net cash (used in) provided by investing activities	(405,874)	12,111
Cash flows from financing activities:		
Proceeds from issuances on line of credit	219,200	323,100
Payments on line of credit	(219,200)	(335,900)
Proceeds from issuance of 10.25% senior notes		434,962
Long-term borrowings under credit facility	165,000	643,300
Repayments of long-term borrowings under credit facility	(297,000)	(1,210,100)
Debt issue costs		(23,857)
Proceeds from financing obligation		18,295
Financing obligation	(257)	
Dividends paid	(12,127)	(10,247)
Proceeds from issuance of common stock, net	224,313	
Proceeds from stock option exercises	1,762	601
Excess tax benefit and other	405	91
Net cash provided by (used in) financing activities	82,096	(159,755)
Net (decrease) increase in cash and cash equivalents	(5,257)	735
Cash and cash equivalents at beginning of year	5,311	240
Cash and cash equivalents at end of period	$ 54	$ 975

The accompanying notes are an integral part of these condensed financial statements.

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BERRY PETROLEUM COMPANY

Condensed Statement of Shareholders Equity

(Unaudited)

(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity
Balances at December 31, 2009	430	18	89,068	674,115	(60,372)	703,259
Issuance of stock	80		224,233			224,313
Exercise of stock options	1		1,760			1,761
Restricted stock issued	1					1
Stock based compensation			7,134			7,134
Tax effect of stock option exercises			405			405
Dividends				(12,127)		(12,127)
Comprehensive income:						
Net income				103,670		103,670
Net change from hedging activity					11,839	11,839
Total comprehensive Income						115,509
Balances at September 30, 2010	$ 512	$ 18	$ 322,600	$ 765,658	$ (48,533)	$ 1,040,255

The accompanying notes are an integral part of these condensed financial statements.

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Berry Petroleum Company

Notes to Condensed Financial Statements

1. Basis of Presentation

These Condensed Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial reporting. All adjustments which are, in the opinion of management, necessary to present fairly Berry Petroleum Company s (the Company) financial position at September 30, 2010, the results of operations for the three and nine months ended September 30, 2010 and 2009, its cash flows for the nine months ended September 30, 2010 and 2009 and shareholders equity for the nine months ended September 30, 2010 have been included. Interim results are not necessarily indicative of expected annual results because of the impact of fluctuations in prices received for oil and natural gas, as well as other factors. In the course of preparing the Condensed Financial Statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events, and, accordingly, actual results could differ from amounts previously established.

The Company s Condensed Financial Statements have been prepared on a basis consistent with the accounting principles and policies reflected in the Company s audited financial statements as of and for the year ended December 31, 2009. The year-end Condensed Balance Sheet was derived from audited Financial Statements included in such report, but does not include all disclosures required by GAAP. The Company has revised comprehensive income (loss) to reflect the correction of a prior period presentation error. The Company has concluded that the presentation error was immaterial to the previously filed financial statements. See Note 4 to the Condensed Financial Statements.

The Company s cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at September 30, 2010 and December 31, 2009 is $24.0 million and $15.7 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

2. Acquisitions and Divestitures

Acquisitions

In March 2010, the Company acquired interests in producing properties principally on 6,900 net acres in the Permian basin of West Texas (W. Texas) for $133 million, comprised of an initial purchase price of $126 million, and customary post-closing adjustments of approximately $7 million (the March Acquisition). The March Acquisition was financed with the proceeds from the issuance of the Company s Class A Common Stock in January 2010. In April 2010, the Company closed on the acquisition of an additional 3,200 net acres in the Permian basin for approximately $14 million, including normal post closing adjustments (the April Acquisition and, together with the March Acquisition, the Permian Basin Acquisitions). The Permian Basin Acquisitions included properties with total proved reserves of approximately 13 MMBOE, of which 83% were crude oil and 21% were proved developed.

The Permian Basin Acquisitions qualify as business combinations and, as such, the Company estimated the fair value of each property as of the acquisition date (the date on which the Company obtained control of the properties). The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs.

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The following table summarizes the consideration paid to the seller and the amounts of the assets acquired and liabilities assumed in the March Acquisition.

		(In thousands)
Consideration paid to seller:		
Cash consideration	$	133,301
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved developed and undeveloped properties		134,546
Other assets acquired		354
Asset retirement obligation		(1,367)
Other liabilities assumed		(232)
Total identifiable net assets	$	133,301

The March Acquisition had an effective date of January 1, 2010, and activity from January 1, 2010 through March 4, 2010 was treated as purchase price adjustments. The preliminary purchase price allocation included an estimate for activity between January 1, 2010 and March 4, 2010; however, actual amounts were greater than the Company s estimate which resulted in an increase to the total cash consideration paid to the seller. As a result, the initial $1.4 million of gain on purchase of oil and natural gas properties recorded in the first quarter of 2010 was reversed in the second quarter of 2010 to reflect the purchase price adjustments.

The following table summarizes the consideration paid to the seller and the amounts of the assets acquired and liabilities assumed in the April Acquisition.

		(In thousands)
Consideration paid to seller:		
Cash consideration	$	14,322
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved developed and undeveloped properties		16,264
Asset retirement obligation		(1,942)
Total identifiable net assets	$	14,322

Acquisition costs of $0.0 million and $2.6 million have been recorded in the Condensed Statements of Income (Loss) under the caption Transaction costs on acquisitions in the three and nine months ended September 30, 2010, respectively. Revenues of $8.4 million and $17.1 million generated by the acquired properties have been included in the accompanying Condensed Statements of Income (Loss) in the three and nine months ended September 30, 2010, respectively. Earnings of $2.9 million and $5.5 million generated by the Permian Basin Acquisitions have been included in the accompanying Condensed Statements of Income (Loss) in the three and nine months ended September 30, 2010, respectively.

Divestitures

On March 3, 2009, the Company entered into an agreement to sell its assets in the Denver-Julesburg basin in Colorado (DJ basin) and related hedges for $154 million before customary closing adjustments. The closing date of the sale of the assets was April 1, 2009. The Company recorded a pre-tax impairment loss of $9.6 million related to the sale, which is reflected within the $6.3 million Income (loss) from discontinued operations, net of taxes, on its Condensed Statement of Income (Loss) for the nine months ended September 30, 2009.

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Income (loss) from discontinued operations, net of taxes, on the accompanying Condensed Statements of Income (Loss) is comprised of the following (in thousands):

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Total revenues	$	$ (578)	$	$ 5,111
Total expenses				16,283
Loss from discontinued operations, before income taxes		(578)		(11,172)
Income tax benefit		1,246		4,849
Income (loss) from discontinued operations, net of taxes	$	$ 668	$	$ (6,323)

3. Shareholders Equity

In January 2010, the Company issued 8 million shares of Class A Common Stock at a price of $29.25 per share. Net proceeds from this offering were $224.3 million after deducting underwriting discounts and commissions and offering expenses. The Company used the net proceeds from the offering to fund the purchase of the March Acquisition (as defined above) and to repay a portion of the outstanding borrowings under the senior secured revolving credit facility. See Note 2 to the Condensed Financial Statements.

4. Earnings per Share and Comprehensive Income (Loss)

Basic (loss) earnings per common share is calculated by dividing adjusted income (loss) available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted (loss) earnings per common share is calculated by dividing (loss) income available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share accordingly.

The two-class method of computing earnings (loss) per share is required for those entities that have participating securities. The two- class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Restricted stock issued prior to January 1, 2010 under the Company s equity incentive plans has the right to receive non-forfeitable dividends, participating on an equal basis with common stock. Restricted stock issued subsequent to January 1, 2010 under the Company s stock incentive plans no longer has the right to receive non-forfeitable dividends. Stock units issued to directors under the Company s nonemployee directors deferred compensation plan also have the right to be credited with non-forfeitable dividends, participating on an equal basis with common stock. Therefore, unvested restricted stock and stock units issued to directors issued prior to January 1, 2010 must be allocated to both common stock and these participating securities under the two-class method. Stock options issued under the Company s stock incentive plans do not participate in dividends.

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The following table shows the computation of basic and diluted earnings (loss) per share from continuing and discontinued operations for the three and nine months ended September, 2010 and 2009 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Net income (loss) from continuing operations	$ (3,023)	$ 18,339	$ 103,670	$ 47,349
Less: income allocable to participating securities		445	2,011	1,153
(Loss) income available for shareholders	$ (3,023)	$ 17,894	$ 101,659	$ 46,196
Net income (loss) from discontinued operations	$	$ 668	$	$ (6,323)
Less: Income allocable to participating securities		17		
Income (loss) from discontinued operations available for shareholders	$	$ 651	$	$ (6,323)
Basic (loss) earnings per share from continuing operations	$ (0.06)	$ 0.41	$ 1.94	$ 1.04
Basic earnings (loss) per share from discontinued operations		0.01		(0.14)
Basic (loss) earnings per share	$ (0.06)	$ 0.42	$ 1.94	$ 0.90
Diluted (loss) earnings per share from continuing operations	$ (0.06)	$ 0.40	$ 1.93	$ 1.03
Diluted earnings (loss) per share from discontinued operations		0.01		(0.14)
Diluted (loss) earnings per share	$ (0.06)	$ 0.41	1.93	$ 0.89
Weighted average shares outstanding - basic	53,007	44,633	52,357	44,607
Add: Dilutive effects of stock options and RSUs		303	386	189
Weighted average shares outstanding - dilutive	53,007	44,936	52,743	44,796

Options to purchase 2.2 million shares and 1.2 million shares were not included in the diluted earnings per share calculation for the three and nine months ended September 30, 2010, respectively, because their effect would have been anti-dilutive. Options to purchase 1.2 million and 1.6 million shares were not included in the diluted earnings (loss) per share calculation for the three and nine months ended September 30, 2009, respectively, because their effect would have been anti-dilutive.

Comprehensive Income (Loss)

Comprehensive income (loss) is a term used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under generally accepted accounting principles are reported as separate components of shareholders equity instead of net income (loss). The components of other comprehensive income (loss) were as follows:

(in millions)	Three months ended September 30, 2010	2009 (1)	Nine months ended September 30, 2010	2009 (1)
Net income (loss)	$ (3,023)	$ 19,007	$ 103,670	$ 41,026
Unrealized gains (losses) on derivatives, net of income taxes of $0, $2,026, $0 and ($49,746), respectively		3,306		(81,166)
Reclassifications of realized (gains) losses, net of income taxes of $2,694, ($1,403), $7,283 and ($30,487), respectively	4,395	(2,289)	11,839	(49,741)
Comprehensive income (loss)	$ 1,372	$ 20,024	$ 115,509	$ (89,881)

(1) The Company revised comprehensive income (loss) to reflect the correction of a prior period presentation error. The table below summarizes the changes:

	For the Three Months Ended September 30, 2009 As Previously Reported	As Revised	For the Nine Months Ended September 30, 2009 As Previously Reported	As Revised
Net income	$ 19,007	$ 19,007	$ 41,026	$ 41,026
Unrealized gains (losses) on derivatives, net of income taxes	(563)	3,306	169,966	(81,166)
Reclassification of realized (gains) losses, net of income taxes	(454)	(2,289)	(39,059)	(49,741)
Comprehensive income (loss)	$ 17,990	$ 20,024	$ 171,933	$ (89,881)

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5. Asset Retirement Obligation (ARO)

The following table summarizes the change in the ARO for the nine months ended September 30 (in thousands):

	2010	2009
Beginning balance at January 1	$ 43,487	$ 41,967
Liabilities incurred	2,825	1,407
Liabilities settled	(1,830)	(293)
Liabilities assumed	3,309	
Disposition of assets		(2,751)
Accretion expense	3,370	2,899
Ending balance at September 30	$ 51,161	$ 43,229

The ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company s oil and gas properties. Inherent in the fair value calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

6. Debt Obligations

Short-term line of credit

Borrowings under the Company s senior secured money market line of credit (the Secured Line of Credit) may be up to $30 million for a maximum of 30 days. The Secured Line of Credit may be terminated at any time upon written notice by either the Company or the lender.

There were no outstanding borrowings on the Secured Line of Credit at September 30, 2010 or December 31, 2009. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1.4%.

Senior secured revolving credit facility

As of September 30, 2010, the Company s senior secured revolving credit facility (the Agreement) has a borrowing base and lender commitments of $938 million. The LIBOR and prime rate margins are between 2.25% and 3.0% based on the ratio of credit outstanding to the borrowing base and the annual commitment fee on the unused portion of the credit facility is 0.50%.

Covenants under the Agreement are as follows:

Total funded debt to EBITDAX (1) ratio not greater than:		Senior secured debt to EBITDAX ratio not greater than:			
2010	Thereafter	to Sep 2010	Mar 2011	Sep 2011	Thereafter
4.50	4.00	3.75	3.50	3.25	3.0

(1) Net income before interest expense, income tax expense, depreciation and amortization expense, exploration expense and non-cash items of income or loss.

The Agreement also contains a current ratio covenant which, as defined, must be at least 1.0. The total outstanding debt at September 30, 2010 under the Agreement, as amended, and the Secured Line of Credit was $240 million and $24 million in letters of credit have been issued under the facility, leaving $674 million in borrowing capacity available under the Agreement. The maximum amount available is subject to semi-annual redeterminations of the borrowing base, based on the value of the Company s proved oil and gas reserves, in April and October of each year in accordance with the lenders customary procedures and practices. Both the Company and the banks have the bilateral right to one additional redetermination each year.

10.25% senior notes due 2014

On May 27, 2009, the Company issued in a public offering $325 million principal amount of 10.25% senior notes due 2014 ($325 million Notes). Interest on the $325 million Notes is paid semi-annually in June and December of each year. The $325 million Notes were issued at a discount to par value of 93.546%, and are carried on the Condensed Balance Sheet at their amortized cost. The

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deferred costs of approximately $9.5 million associated with the issuance of this debt are being amortized over the five year life of the $325 million Notes.

On August 13, 2009, the Company issued in a public offering an additional $125 million principal amount of its 10.25% senior notes due 2014 ($125 million Notes and, together with the $325 million Notes, the Notes). The $125 million Notes were issued at a premium to par value of 104.75%, and are carried on the Condensed Balance Sheet at their amortized cost. The deferred costs of approximately $1.9 million associated with the issuance of this debt are being amortized over the five year life of the $125 million Notes.

The $125 million Notes and the $325 million Notes are treated as a single series of debt securities and are carried on the Condensed Balance Sheet at their combined amortized cost.

8.25% senior subordinated notes due 2016

In 2006, the Company issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Sub notes). Interest on the Sub notes is paid semiannually in May and November of each year. The deferred costs of approximately $5.2 million associated with the issuance of this debt are being amortized over the ten year life of the Sub notes.

Financial Covenants

The Agreement contains restrictive covenants as described above. Under the Company s Notes and Sub notes as long as the interest coverage ratio (as defined) is greater than 2.5 times, the Company may incur additional debt. The Company was in compliance with all of these covenants as of September 30, 2010.

	As of September 30, 2010
Current Ratio (Not less than 1.0)	4.65
Total Funded Debt Ratio to EBITDAX (Not greater than 4.50)	2.38
Interest Coverage Ratio (Not less than 2.5)	4.40
Senior Secured Debt Ratio to EBITDAX (Not greater than 3.75)	0.69

The weighted average interest rate on the Company s total outstanding borrowings was 7.7% and 7.0% at September 30, 2010 and December 31, 2009, respectively.

7. Fair Value Measurements

The authoritative guidance for fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

A financial instrument s categorization within the fair value hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. The Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) for valuation as a practical expedient for assigning fair value. Oil swaps, natural gas swaps and interest rate swaps are valued using models which are based on active market data and are classified within Level 2 of the fair value hierarchy. Derivatives that are valued based upon models with significant unobservable market inputs (primarily volatility), and that are normally traded less actively are classified within Level 3 of the valuation hierarchy. Fair value of all derivative instruments are estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The fair value of all derivative instruments are estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services, and the Company has made no adjustments to the obtained prices. The pricing services publish observable market information from multiple brokers and exchanges. No proprietary models are used by the pricing services for the inputs. All valuations were compared against counterparty valuations to verify the reasonableness of prices. The Company also considers counterparty credit risk and its own credit risk in its determination of all estimated fair values. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative contracts it holds. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

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The following tables set forth by level within the fair value hierarchy the Company s net derivative assets and liabilities that were measured at fair value on a recurring basis as of September 30, 2010 and December 31, 2009.

Assets and liabilities measured at fair value on a recurring basis

September 30, 2010 (in millions)		**Total carrying value on the Condensed Balance Sheet**		**Level 2**		**Level 3**
Commodity derivatives liability, net	$	(57.2)	$	(15.7)	$	(41.5)
Interest rate derivatives liability, net		(11.8)		(11.8)		
Total derivative liabilities, net at fair value	$	(69.0)	$	(27.5)	$	(41.5)

December 31, 2009 (in millions)		**Total carrying value on the Condensed Balance Sheet**		**Level 2**		**Level 3**
Commodity derivatives liability, net	$	(88.5)	$	(62.5)	$	(26.0)
Interest rate derivatives liability, net		(8.9)		(8.9)		
Total derivative liabilities, net at fair value	$	(97.4)	$	(71.4)	$	(26.0)

Changes in Level 3 fair value measurements

The table below includes a rollforward of the Condensed Balance Sheet amounts (including the change in fair value) for financial instruments classified by the Company within Level 3 of the fair value hierarchy. When a determination is made to classify a financial instrument within Level 3 of the fair value hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources).

	Three months ended September 30,				**Nine months ended September 30,**			
(in millions)		**2010**		**2009**		**2010**		**2009**
Fair value (liability) asset, beginning of period	$	(4.0)	$	43.1	$	(26.0)	$	172.5
Total realized and unrealized gains (losses)								
Realized and unrealized (loss) gain included in income		(25.6)		14.1		16.3		55.6
Unrealized (loss) gain included in accumulated other comprehensive loss				(10.4)				(142.2)
Purchases, sales and settlements, net		(11.9)		(14.2)		(31.8)		(56.7)
Transfers into and/or out of Level 3								3.4
Fair value (liability) asset, end of period	$	(41.5)	$	32.6	$	(41.5)	$	32.6
Total unrealized (loss) gain included in income related to financial assets and liabilities still on the Condensed Balance Sheet at September 30, 2010 and 2009	$	(37.5)	$	(0.2)	$	(15.5)	$	(1.2)

The $3.4 million of transfers out of Level 3 for the nine months ended September 30, 2009 represent crude oil collars that were converted to crude oil swaps during the first quarter of 2009.

For further discussion related to the Company s derivatives see Note 8 to the Condensed Financial Statements.

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Fair Market Value of Financial Instruments

The Company used various assumptions and methods in estimating the fair values of its financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short-term maturity of these instruments. The carrying amount of the Company s credit facilities approximated fair value, because the interest rates on the credit facilities are variable and could be at similar rates today. The fair values of the 8.25% senior subordinated notes due 2016 and the 10.25% senior notes due 2014 were estimated based on quoted market prices. The fair values of the Company s derivative instruments and other investments are discussed above.

	As of September 30, 2010			
(in millions)		**Carrying Amount**		**Estimated Fair Value**
Line of credit	$		$	
Senior secured revolving credit facility		240		240
8.25% Senior subordinated notes due 2016		200		207
10.25% Senior notes due 2014		438		493
	$	878	$	940

	As of December 31, 2009			
(in millions)		**Carrying Amount**		**Estimated Fair Value**
Senior secured revolving credit facility	$	372	$	372
8.25% Senior subordinated notes due 2016		200		196
10.25% Senior notes due 2014		437		487
	$	1,009	$	1,055

8. Derivative Instruments

The Company uses financial derivative instruments as part of its price risk management program to achieve a more predictable, economic cash flow from its oil and natural gas production by reducing its exposure to price fluctuations. The Company has entered into financial commodity swap and collar contracts to fix the floor and ceiling prices received for a portion of the Company s oil and natural gas production. The terms of the contracts depend on various factors, including management s view of future crude oil and natural gas prices, acquisition economics on purchased assets and future financial commitments. The Company periodically enters into interest rate derivative agreements to protect against changes in interest rates on its floating rate debt. For further discussion related to the fair value of the Company s derivatives see Note 7 to the Condensed Financial Statements.

As of September 30, 2010, the Company had the following commodity derivatives:

	2010	**2011**	**2012**	**2013**
Oil Bbl/D:	15,930	15,520	10,000	4,000
Natural Gas MMBtu/D:	19,000	15,000	15,000	

The Company entered into the following crude oil two-way collars during the nine months ended September 30, 2010:

Term	**Average Barrels Per Day**	**Floor/Ceiling Prices**
Full year 2010	500	$75.00/$93.95
Full year 2010	500	$75.00/$94.45
Full year 2011	500	$75.00/$100.75
Full year 2011	500	$75.00/$101.15
Full year 2011	1,000	$75.00/$91.25
Full year 2012	500	$75.00/$105.00
Full year 2012	500	$75.00/$106.00
Full year 2012	1,000	$75.00/$95.00

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The Company entered into the following crude oil three-way collars during the nine months ended September 30, 2010:

Term	Average Barrels Per Day	Floor/Swap/Ceiling Prices
Full year 2011	1,000	$60.00 / $80.00 / $101.00
Full year 2011	1,000	$55.00 / $75.00 / $91.63
Full year 2011	500	$65.00 / $85.00 / $97.25
Full year 2011	1,000	$69.70 / $85.00 / $100.0
Full year 2011	1,000	$70.00 / $86.85 / $100.00
Full year 2012	1,000	$69.70 / $85.00 / $100.00
Full year 2012	1,000	$70.00 / $86.85 / $100.00
Full year 2012	1,000	$60.00 / $80.00 / $120.00
Full year 2012	1,000	$60.00 / $80.00 / $96.92
Full year 2012	1,000	$65.00 / $85.00 / $97.25
Full year 2013	1,000	$60.00 / $80.00 / $103.30
Full year 2013	1,000	$70.00 / $86.85/ $100.00
Full year 2013	1,000	$69.70 / $85.00 / $100.00
Full year 2013	1,000	$65.00 / $85.00 / $97.25

The Company entered into the following natural gas swaps during the nine months ended September 30, 2010:

Term	Average MMBtus Per Day		Swap Prices
Full year 2011	5,000	$	5.50
Full year 2012	5,000	$	5.75

Discontinuance of cash flow hedge accounting

Prior to January 1, 2010, the Company designated most of its commodity and interest rate derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to Accumulated other comprehensive loss (AOCL). Effective January 1, 2010, the Company elected to de-designate all of its commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009. As a result, subsequent to December 31, 2009, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCL.

At December 31, 2009, AOCL consisted of $97.4 million, ($60.4 million, net of tax) of unrealized losses, representing the change in the fair value of the Company s open commodity and interest rate derivative contracts designated as cash flow hedges as of that balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such fair values at December 31, 2009 are frozen in AOCL as of the de-designation date and reclassified into earnings as the original hedge transactions settle. During the three and nine months ended September 30, 2010, $7.1 million ($4.4 million, net of tax) and $19.1 million ($11.8 million, net of tax), respectively, of amortization of AOCL relating to de-designated commodity and interest rate hedges were reclassified from AOCL into earnings. As of September 30, 2010, AOCL consisted of $78.3 million ($48.5 million, net of tax) of unrealized losses on commodity and interest rate derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from AOCL after-tax net losses of $33.4 million related to de-designated commodity and interest rate derivative contracts during the next twelve months.

At September 30, 2010, the net fair value derivative liability was $69.0 million as compared to a net fair value derivative liability of $97.4 million at December 31, 2009 which reflects changes in commodity prices and interest rates. Based on NYMEX futures pricing as of September 30, 2010, the Company expects to make net payments under the existing derivatives of $30.9 million during the next twelve months.

The Company presents its derivative assets and liabilities on its Condensed Balance Sheets on a net basis, whenever it has a legally enforceable master netting agreement with a counterparty to a derivative contract. The Company uses these agreements to manage and reduce its potential counterparty credit risk. The related cash flow impact of all of the Company s derivatives is reflected in cash flows from operating activities.

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The following tables detail the fair value of derivatives recorded on the Company s Condensed Balance Sheets, by category:

	As of September 30, 2010					
	Derivative Assets			Derivative Liabilities		
(in millions)	**Balance Sheet Classification**		**Fair Value**	**Balance Sheet Classification**		**Fair Value**
Total derivatives designated as hedging instruments		$			$	
Current:						
Commodity	Derivative assets	$	6.2	Derivative assets	$	
Commodity	Derivative liabilities			Derivative liabilities		38.7
Interest rate	Derivative assets			Derivative assets		0.8
Interest rate	Derivative liabilities			Derivative liabilities		6.2
Long term:						
Commodity	Derivative assets		3.6	Derivative assets		
Commodity	Derivative liabilities			Derivative liabilities		28.3
Interest rate	Derivative assets			Derivative assets		0.5
Interest rate	Derivative liabilities			Derivative liabilities		4.3
Total derivatives not designated as hedging instruments		$	9.8		$	78.8
Total derivatives		$	9.8		$	78.8

	As of December 31, 2009					
	Derivative Assets			Derivative Liabilities		
(in millions)	**Balance Sheet Classification**		**Fair Value**	**Balance Sheet Classification**		**Fair Value**
Current:						
Commodity	Derivative assets	$	15.5	Derivative assets	$	
Commodity	Derivative liabilities		0.2	Derivative liabilities		30.8
Interest Rate	Derivative assets			Derivative assets		3.5
Interest Rate	Derivative liabilities			Derivative liabilities		2.7
Long term:						
Commodity	Derivative assets		0.4	Derivative assets		
Commodity	Derivative liabilities		1.2	Derivative liabilities		74.1
Interest rate	Derivative assets		0.3	Derivative assets		
Interest rate	Derivative liabilities			Derivative liabilities		3.0
Total derivatives designated as hedging instruments		$	17.6		$	114.1
Current:						
Commodity		$		Derivative assets	$	0.4
Commodity				Derivative liabilities		0.5
Total derivatives not designated as hedging instruments		$			$	0.9
Total derivatives		$	17.6		$	115.0

The tables below summarize the location and the amount of derivative instrument gains (losses) before income taxes reported in the Condensed Statements of Income (Loss) for the periods indicated (in millions):

Derivatives cash flow hedging relationships	Location of Gain (Loss) Recognized in Income	Three months ended September 30 2010	2009	Nine months ended September 30, 2010	2009
Commodity					
Gain (loss) recognized in AOCL (effective portion)	Accumulated other comprehensive (loss)	$	$ 9.3	$	$ (128.9)
(Loss) gain reclassified from AOCL into income (effective portion)	Sales of oil and gas	(5.2)	5.6	(12.1)	84.7
(Loss) recognized in income (ineffective Portion)	Realized and unrealized (loss) gain on derivatives, net		(0.6)		(0.2)
Interest rate					
(Loss) gain recognized in AOCL (effective portion)	Accumulated other comprehensive (loss)	$	$ (4.5)	$	$ (2.4)
(Loss) gain reclassified from AOCL into income (effective portion)	Interest	(1.9)	(1.9)	(7.0)	(4.4)
Gain (Loss) recognized in income (ineffective portion)	Realized and unrealized (loss) gain on derivatives, net		0.1		(0.2)

Amount of gain or (loss) recognized in income on derivatives not designated as hedging instruments under authoritative guidance for the periods indicated (in millions):

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Derivatives not designated as Hedging Instruments under authoritative guidance	Location of Gain (Loss) Recognized in Income	Three Months ended September 30, 2010	Three Months ended September 30, 2009	Nine Months ended September 30, 2010	Nine Months ended September 30, 2009
Commodity	Realized and unrealized gain (loss) on derivatives, net	$ (24.8)	$ 1.1	$ 38.9	$ (7.2)
Commodity	Loss from discontinued operations, net of taxes				(0.5)
Interest Rates	Realized and unrealized gain (loss) on derivatives, net	(2.4)		(8.4)	

Credit risk

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the agreements with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions the Company s maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that the Company would have incurred if all counterparties to its derivative contracts failed to perform at September 30, 2010 was $8.5 million. The credit rating of each of the counterparties was AA-/Aa3, or better, as of September 30, 2010. As of September 30, 2010, the Company s largest three counterparties accounted for 78% of the value of its total derivative positions.

As of September 30, 2010, the counterparties to the Company s commodity derivative contracts consist of nine financial institutions. The Company s counterparties or their affiliates are generally also lenders under the Company s senior revolving credit facility. As a result, the counterparties to the Company s derivative agreements share in the collateral supporting the Company s senior secured revolving credit facility. The Company is not generally required to post additional collateral under derivative agreements.

Certain of the Company s derivative agreements contain provisions that require cross defaults and acceleration of those instruments to any material debt. If the Company was to default on any of its material debt agreements, it would be a violation of these provisions, and the counterparties to the derivative instruments could request immediate payment on derivative instruments that are in a net liability position at that time. As of September 30, 2010, the Company was in a net liability position with six of the counterparties to the Company s derivative instruments, totaling $77.5 million.

9. Dry hole, abandonment, impairment and exploration

During the three and nine months ended September 30, 2010, the Company incurred dry hole, abandonment, impairment and exploration expense of $0.6 million and $2.2 million, respectively, which was primarily a result of a mechanical failure encountered on one well in the Piceance basin. The well was abandoned in favor of drilling a replacement well from the same well pad. During the three and nine months ended September 30, 2009, the Company incurred dry hole, abandonment, impairment and exploration expense of $0.1 million and $0.2 million, respectively.

10. Income Taxes

The effective income tax rate for the three months ended September 30, 2010 and 2009 was 20.8% and 36.2%, respectively. The effective income tax rate was 38.3% and 34.3% for the nine months ended September 30, 2010 and 2009, respectively. The decrease in the effective tax rate in the third quarter of 2010 compared to the third quarter of 2009 is due a to one-time charge recorded in 2010 for actual tax return results and the relative weight of the one-time charge to the third quarter 2010 pre-tax loss. The increase in the effective tax rate for the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009 is due to a one-time reduction in the overall state deferred tax rate in 2009 and to a one-time reduction in uncertain tax positions in 2009. The 2009 state tax rate reduction relates to acquisitions made in lower tax jurisdictions that reduced total future state tax obligations. The Company s estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences.

As of September 30, 2010, the Company had a gross liability for uncertain tax benefits of $5.3 million all of which, if recognized, would affect the effective tax rate. There were no significant changes to the calculation since December 31, 2009. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. The Company had accrued approximately $0.8 million and $0.7 million of interest related to its uncertain tax positions as of September 30, 2010 and December 31, 2009, respectively.

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11. Bad Debt Recovery

The Company recognized $38.5 million in bad debt expense in the year ended December 31, 2008 related to Flying J, Inc., its wholly owned subsidiary Big West Oil, LLC and its wholly owned subsidiary Big West of California, LLC (BWOC) filing for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code on December 22, 2008. On July 6, 2010, the Joint Plan of Reorganization of Flying J, Inc., BWOC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United State Bankruptcy Code. Additionally, on July 6, 2010, the United States Bankruptcy Court approved and confirmed that certain June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of the Company s claim in Flying J s pending bankruptcy. Pursuant to the Stipulation, each of the Company and Flying J agreed that the total amount owed to the Company by Flying J was $60.5 million and, as a result, the Company received $60.5 million in cash on July 23, 2010. In the quarter ended September 30, 2010, the Company recorded a settlement of its Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

12. Commitments and Contingencies

The Company s contractual obligations not included in its Condensed Balance Sheet as of September 30, 2010 (except Long-term debt and Asset retirement obligation) are as follows (in millions):

	Total	2010	2011	2012	2013	2014	Thereafter
Long-term debt and interest	$ 1,170.6	$ 17.2	$ 68.8	$ 306.0	$ 62.6	$ 485.7	$ 230.3
Asset retirement obligation	51.2	0.9	2.9	2.9	2.8	2.8	38.9
Operating lease obligations	15.1	0.7	2.7	2.7	2.7	2.6	3.7
Drilling and rig obligations	27.7	3.0	24.7				
Firm natural gas transportation contracts	121.7	4.9	19.7	17.6	15.7	14.8	49.0
Total	$ 1,386.3	$ 26.7	$ 118.8	$ 329.2	$ 83.8	$ 505.9	$ 321.9

Operating leases

The Company leases corporate and field offices in California, Colorado and Texas. Rent expense with respect to its lease commitments was $0.5 million for both the three months ended September 30, 2010 and 2009, and was $1.6 million for both the nine months ended September 30, 2010 and 2009.

In 2006, the Company purchased a corporate aircraft which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

Drilling obligations

Included in the table above are the Company s contractual obligations on its Piceance assets in Colorado. The Company must spud an additional 87 wells of its original 120 wells commitment by February 2011 to avoid penalties of $0.2 million per well not drilled. Satisfying this commitment and further developing these assets depends on Piceance infrastructure and access, drilling resources, including capital availability, and other factors, all of which will be further evaluated throughout the remainder of 2010.

Firm natural gas transportation

In July 2009, the Company closed on the financing of its E. Texas gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term gas gathering agreements for the E. Texas production which contained an embedded lease. There is no minimum payment required under these agreements. For the three months ended September 30, 2010 and 2009, the Company incurred $1.8 million and $1.0 million, respectively, under the agreements. For the nine months ended September 30, 2010 and 2009, the Company incurred $4.6 million and $1.0 million, respectively, under the agreements.

In June 2009, the Company amended its natural gas firm transportation agreement with Enbridge Pipelines providing for transportation of its gas from Tex-OK to Orange County, Florida (Zone 1). The agreement provides for minimum volume of 25,000 MMBtu/d and a maximum volume of 55,000 MMBtu/D.

The Company has long-term firm transportation contracts that total 35,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. The Company pays a demand charge for this capacity and its own production did not completely fill that capacity. To maximize the utilization of its firm transportation, the Company bought its working interest partners share of the gas produced in the Piceance basin at the market rate for that area and used its excess transportation to move this gas to

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the sales point. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Income (Loss) for the three months ended September 30, 2010 and 2009 is $0.9 million and $0.6 million, respectively. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Income (Loss) for the nine months ended September 30, 2010 and 2009 is $2.0 million and $1.5 million.

Berry has signed firm transportation service agreements with El Paso Corporation for an average total of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. The expectation is that the project will proceed and be in service in 2011.

Other commitments

The Company is a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of a minimum of 5,000 Bbl/D of its Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company s 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company s crude oil. Gross oil production from the Company s Uinta properties averaged approximately 3,040 Bbl/D in the first nine months of 2010.

The Company has no material accrued environmental liabilities for its sites, including sites in which governmental agencies have designated the Company as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in substantial costs incurred. The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material effect on its financial position, results of operations or liquidity.

Certain of the Company s royalty payment calculations are being disputed. The Company believes that its royalty calculations are in accordance with applicable leases and other agreements. However, the disputed amounts that the Company may be required to pay are up to approximately $6 million.

In July 2009, the Company received a notice of proposed civil penalty from the Bureau of Land Management (BLM) related to the Company s alleged non-compliance during 2007 with regulations relating to the operation and position of certain valves in its Uinta basin operations. The proposed civil penalty was $69.6 million and reflects the theoretical maximum penalty amount under applicable regulations, absent mitigating factors. In 2007 the Company immediately remediated the instances of non-compliance, cooperated fully with the BLM s investigation and the Company believes no production was lost, all royalties were paid and there was no harm to the environment. Due to the above mitigating factors, among others, the Company believes this matter will be resolved by the payment of a penalty that will not exceed $2.1 million. The Company recorded $2.1 million in general and administrative expense in the second quarter of 2009.

On October 7, 2010, the Company executed agreements with PG&E, which, if approved by the California Public Utilities Commission (CPUC), will extend the power contracts for its 18MW and 38MW facilities until June 30, 2011. The electricity sales contracts with Edison for our

Placerita facility will continue in effect until the CPUC approves and makes available replacement standard form Qualifying Facilities (QF) contracts. Such contracts are the subject of a settlement agreement dated October 8, 2010 among the three California public utilities, two consumer representative groups and three parties that represent the interests of the majority of the cogeneration facilities in the state, including the Company, that if adopted by the CPUC would resolve numerous issues including the issue of new or extended contracts for QF s such as the Company. A ruling on the settlement is expected later in 2010 or early 2011; however, the current contracts could terminate earlier under certain limited circumstances.

13. Subsequent Event

On October 22, 2010, the Company entered into an agreement with a group of private sellers to acquire the interests in producing properties principally in the Wolfberry trend in West Texas for approximately $175 million in cash. The effective date of the transaction is October 1, 2010. The acquisition is expected to close in the fourth quarter of 2010, subject to certain closing conditions.

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Berry Petroleum Company

Management s Discussion and Analysis of Financial Condition and Results of Operations

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

The following is management s discussion and analysis of certain significant factors that have affected aspects of our financial position and the results of operations during the periods included in the accompanying Condensed Financial Statements. You should read this in conjunction with the discussion under Management s Discussion and Analysis of Financial Condition and Results of Operations and the audited Financial Statements for the year ended December 31, 2009 included in our Annual Report on Form 10-K, as amended, and the Condensed Financial Statements included elsewhere herein.

The profitability of our operations in any particular accounting period will be directly related to the realized prices of oil, gas and electricity sold, the type and volume of oil and gas produced and electricity generated and the results of development, exploitation, acquisition, exploration and hedging activities. The realized prices for natural gas and electricity will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by global supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. We benefit from lower natural gas prices as we are a consumer of natural gas in our California operations. In the Rocky Mountains and E. Texas we benefit from higher natural gas pricing. The cost of natural gas used in our steaming operations and electrical generation, production rates, labor, equipment costs, maintenance expenses, and production taxes are expected to be the principal influences on operating costs. Accordingly, our results of operations may fluctuate from period to period based on the foregoing principal factors, among others.

Notable Third Quarter Items.

- Achieved production averaging 33,870 BOE/D, comprised of 64% crude oil, up 3% from the second quarter of 2010
- Received approval from the California Division of Oil, Gas and Geothermal Resources for the next phase of development of our diatomite asset
- Executed a one year crude oil purchase contract with ExxonMobil Oil Corporation for the sale of all the oil production from our Midway Sunset Field
- Executed a three rig drilling program in the Permian basin and increased production to 1,340 BOE/D, up 30% from the second quarter of 2010
- Determined that McKittrick 21Z cyclic development is economic and plan to expand development in 2011
- Generated discretionary cash flow **(1)** of $95 million

Notable Items and Expectations for the Fourth Quarter and Full Year 2010.

- Entered into an agreement with a group of private sellers to acquire their interests in producing properties principally in the Wolfberry trend in West Texas
- Planning to run a two rig drilling development program in the diatomite for the remainder of 2010
- Anticipating 2010 average production between 32,250 and 33,000 BOE/D, an 8% to 10% increase over 2009
- Expecting 2010 development capital between $290 million and $310 million to be fully funded from operating cash flow
- Expecting 2011 development capital between $375 million and $425 million at $75 WTI, primarily focused on the development of our oil assets
- Anticipating average 2011 production between 37,000 and 39,000 BOE/D

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(1) Discretionary cash flow is considered a non-GAAP performance measure and reference should be made to *Reconciliation of Non-GAAP Measures* at the end of this Item 2 for further explanation of this performance measure, as well as a reconciliation to the most directly comparable GAAP measure.

Results of Operations.

In the third quarter of 2010, we reported a net loss from continuing operations of $3.0 million, or $0.6 per diluted share, and net cash flows from operations of $183.7 million. Net loss from continuing operations includes a $23.6 million loss on derivatives as a result of non-cash changes in fair values and amortization of frozen fair values.

During the first nine months of 2010, we reported net income from continuing operations of $103.7 million, or $1.93 per diluted share, and net cash flows from operations was $318.5 million. Net income from continuing operations includes a $6.4 million gain on derivatives as result of non-cash changes in fair values and amortization of frozen fair values and a $37.3 million Flying J settlement,

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offset by $1.0 million of dry hole costs and $1.6 million of transaction related costs related to the acquisition of certain properties in the Permian basin, as discussed below.

Acquisitions.

Permian Basin Acquisitions. Through April, 2010, we acquired interests in producing properties principally in the Permian basin of West Texas from private sellers for approximately $147 million, including normal post closing adjustments. These properties are located primarily within the Wolfberry play and production from these properties is approximately 1,700 BOED at present.

With the acquisitions announced on October 25, 2010, we have accumulated approximately 19,350 net acres in the Wolfberry trend. The acquisitions in 2010 will provide a five-year drilling inventory in the Permian basin with approximately 400 locations based on 40-acre spacing with an additional 400 potential locations based on 20-acre spacing.

Revenues.

Approximately 82% of our revenues are generated through the sale of oil and natural gas production under either negotiated contracts or spot gas purchase contracts at market prices. Approximately 5% of our revenues are derived from electricity sales from cogeneration facilities which supply approximately 28% of our steam requirement for use in our California thermal heavy oil operations. We have invested in these facilities for the purpose of lowering our steam costs, which are significant in the production of heavy crude oil. Approximately 3% of our revenues are derived from gas marketing sales which represent our excess capacity on the Rockies Express pipeline which we use to market natural gas purchased from our working interest partners.

The following results from continuing operations are in millions (except per share data) for the three and nine month periods ended:

	Three months ended,			Nine months ended,	
	September 30, 2010	**September 30, 2009**	**June 30, 2010**	**September 30, 2010**	**September 30, 2009**
Sales of oil	$ 123	$ 109	$ 125	$ 369	$ 311
Sales of gas	29	18	27	82	63
Total sales of oil and gas	$ 152	$ 127	$ 152	$ 451	$ 374
Sales of electricity	9	9	8	27	26
Gas marketing	5	5	5	18	18
Realized and unrealized (loss) gain on derivatives, net	(27)	1	56	31	7
Settlement on Flying J bankruptcy claim			22	22	
Interest and other income, net		1	1	2	2
Total revenues and other income	$ 139	$ 143	$ 244	$ 551	$ 427
Net income (loss) from continuing operations	$ (3)	$ 18	$ 89	$ 104	$ 47

Diluted (loss) earnings per share from continuing operations	$	(0.06)	$	0.40	$	1.64	$	1.93	$	1.03

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Operating Data. The following table is for the three months ended:

	September 30, 2010	%	September 30, 2009	%	June 30, 2010	%
Heavy oil production (Bbl/D)	16,722	49	16,780	59	17,492	54
Light oil production (Bbl/D)	5,049	15	2,530	9	4,377	13
Total oil production (Bbl/D)	21,771	64	19,310	68	21,869	67
Natural gas production (Mcf/D)	72,576	36	54,637	32	65,909	33
Total (BOE/D)	33,867	100	28,417	100	32,854	100
Oil and gas BOE for continuing operations:						
Average realized sales price	$ 48.73		$ 47.49		$ 50.81	
Average sales price including cash derivative settlements	51.88		46.39		53.11	
Oil, per Bbl for continuing operations:						
Average WTI price	$ 76.20		$ 68.24		$ 78.05	
Price sensitive royalties	(2.91)		(2.36)		(2.90)	
Quality differential and other (a)	(8.87)		(8.78)		(9.71)	
Crude oil derivatives non cash amortization (b)	(2.89)				(2.42)	
Crude oil derivatives cash settlements (c)			2.28			
Oil revenue	$ 61.53		$ 59.38		$ 63.02	
Add: Crude oil derivatives non cash amortization	2.89				2.42	
Crude oil derivative cash settlements (d)	1.14		(1.41)		0.01	
Average realized oil price	$ 65.56		$ 57.97		$ 65.45	
Natural gas price for continuing operations:						
Average Henry Hub price per MMBtu	$ 4.38		$ 3.39		$ 4.09	
Conversion to Mcf	0.22		0.17		0.20	
Natural gas derivatives non cash amortization (b)	0.09				0.12	
Natural gas derivative cash settlements (c)			0.27			
Location, quality differentials and other	(0.40)		(0.28)		0.02	
Natural gas revenue per Mcf	$ 4.29		$ 3.55		$ 4.43	
Less: Natural gas derivatives non cash amortization	(0.09)				(0.12)	
Natural gas derivative cash settlements (d)	0.35		(0.07)		0.46	
Average realized natural gas price per Mcf	$ 4.55		$ 3.48		$ 4.77	

(a) California differential ranged from a low of $6.11 to a high of $8.17 per barrel during the third quarter of 2010 compared to a low of $7.27 and a high of $8.45 per barrel during the third quarter of 2009

(b) Includes non-cash amortization of frozen December 31, 2009 fair values resulting from January 1, 2010 discontinuing of hedge accounting, recorded in Oil and natural gas sales

(c) Includes cash settlements on derivatives prior to January 1, 2010, for which we had elected hedge accounting, recorded in Oil and natural gas sales

(d) Includes cash settlements on derivatives recorded in Realized and unrealized gain (loss) on derivatives, net

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The following table is for the nine months ended:

	September 30, 2010	%	September 30, 2009	%
Heavy oil production (Bbl/D)	17,318	54	16,691	55
Light oil production (Bbl/D)	4,069	13	2,892	10
Total oil production (Bbl/D)	21,387	67	19,583	65
Natural gas production (Mcf/D)	64,002	33	64,493	35
Total operations (BOE/D)	32,054	100	30,332	100
DJ Basin Production (BOE/D)			1,020	
Production - Continuing Operations (BOE/D)			29,312	
Oil and gas BOE for continuing operations:				
Average realized sales price	$ 51.63		$ 46.80	
Average sales price including cash derivative settlements	53.87		46.43	
Oil, per Bbl, for continuing operations:				
Average WTI price	$ 77.70		$ 57.22	
Price sensitive royalties	(2.95)		(1.83)	
Quality differential and other (a)	(8.94)		(8.65)	
Crude oil derivatives non cash amortization (b)	(2.36)			
Crude oil derivative cash settlements (c)			11.49	
Oil Revenue	$ 63.45		$ 58.23	
Add: Crude oil derivatives non cash amortization	2.36			
Crude oil derivative cash settlements (d)	0.33		(0.49)	
Average realized oil price	$ 66.14		$ 57.74	
Natural gas price for continuing operations:				
Average Henry Hub price per MMBtu	$ 4.60		$ 3.94	
Conversion to Mcf	0.23		0.20	
Natural gas derivatives non cash amortization (b)	0.10			
Natural gas derivative cash settlements (c)			0.56	
Location, quality differentials and other	(0.26)		(0.74)	
Natural gas revenue per Mcf	$ 4.67		$ 3.96	
Less: Natural gas derivatives non cash amortization	(0.10)			
Natural gas derivative cash settlements (d)	0.32		(0.02)	
Average realized natural gas price per Mcf	$ 4.89		$ 3.94	

(a) California differential ranged from a low of $6.11 to a high of $8.95 per barrel during the nine months ended September 30, 2010 compared to a low of $5.20 and a high of $14.02 per barrel during the nine months ended September 30, 2009.

(b) Includes non-cash amortization of frozen December 31, 2009 fair values resulting from January 1, 2010 discontinuing of hedge accounting, recorded in Oil and natural gas sales

(c) Includes cash settlements on derivatives prior to January 1, 2010, for which we had elected hedge accounting, recorded in Oil and natural gas sales

(d) Includes cash settlements on derivatives recorded in Realized and unrealized gain (loss) on derivatives, net

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Sales of Oil and Gas.

Sales of oil and gas increased $25 million, or 20%, to $152 million in third quarter of 2010 compared to $127 million in the third quarter of 2009. The increase is due primarily to a 19% increase in sales volumes and an increase in the average sales price to $48.73 per BOE in the third quarter of 2010 from $47.49 per BOE in the third quarter of 2009. Sales of oil and gas in the third quarter of 2010 are relatively unchanged from the second quarter of 2010. Approximately 64% of our oil and gas sales volumes in the third quarter of 2010 were crude oil, with 77% of the crude oil being heavy oil produced in California which was sold under various contracts with prices tied to the San Joaquin posted price.

Sales of oil and gas increased $77 million, or 21%, to $451 million in the nine months ended September 30, 2010 compared to $374 million in the nine months ended September 30, 2009. The increase is primarily due to a 9% increase in sales volume and an increase in the average sales price to $51.63 per BOE for the nine months ended September 30, 2010 from $46.80 per BOE for the nine months ended September 30, 2009.

Effective January 1, 2010, we elected to de-designate all of our commodity derivative contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. As a result of discontinuing hedge accounting on January 1, 2010, changes in fair values at December 31, 2009 are frozen in accumulated other comprehensive loss (AOCL) as of the de-designation date and will be reclassified into oil and gas sales in future periods as the original hedged transactions affect earnings. As a result, in the three and nine months ended September 30, 2010, we reclassified $5.2 million and $12.1 million, respectively, of non-cash derivative losses relating to de-designated commodity hedges from AOCL into earnings under the caption Sales of oil and gas. Beginning January 1, 2010 all of our derivative contract fair value gains and losses are recognized immediately in earnings as Realized and unrealized gain (loss) on derivatives, net. Cash flow is impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded to earnings as Realized and unrealized gain (loss) on derivatives, net. See Realized and unrealized (loss) gain on derivatives, net below.

Sales of Electricity.

Sales of electricity increased in the third quarter of 2010 compared to the third quarter of 2009 due to a 17% increase in electricity prices. Electricity operating costs increased in the third quarter of 2010 compared to the third quarter of 2009 due to a 28% increase in fuel gas cost. Sales of electricity increased in the third quarter of 2010 compared to the second quarter of 2010 due to a 5% increase in sales volumes and a 12% increase in electricity prices. Electricity operating costs decreased in the third quarter of 2010 compared to the second quarter of 2010 due to a 3% decrease in fuel gas cost. We purchased approximately 27,227 MMBtu/D and 26,102 MMBtu/D of natural gas as fuel for use in our cogeneration facilities for the three months ended September 30, 2010 and June 30, 2010, respectively.

Sales of electricity increased in the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009 as a result of a 1% increase in sales volume and a 2% increase in electricity prices. Electricity operating costs increased in the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009 due to 35% higher fuel gas cost.

	Three months ended			Nine months ended	
	September 30, 2010	**September 30, 2009**	**June 30, 2010**	**September 30, 2010**	**September 30, 2009**

Electricity										
Revenues (in millions)	$	9.5	$	9.1	$	7.9	$	27.3	$	26.0
Operating costs (in millions)	$	7.2	$	6.9	$	7.8	$	24.7	$	22.1
Electric power produced - MWh/D		2,091		2,048		2,009		2,084		2,048
Electric power sold - MWh/D		1,933		1,966		1,840		1,917		1,896
Average sales price/MWh	$	53.15	$	45.24	$	47.47	$	67.42	$	65.88
Fuel gas cost/MMBtu (including transportation)	$	4.16	$	3.26	$	4.29	$	4.66	$	3.44

Natural Gas Marketing.

We have long-term firm transportation contracts for our Piceance natural gas production, with total capacity of 35,000 MMBtu/D. We pay a demand charge for this capacity and our own production does not currently fill that capacity. In order to maximize our firm transportation, we bought our partners share of the gas produced in the Piceance at the market rate for that area. We used our excess transportation to move this gas to where it was eventually sold. The pre-tax net of our gas marketing revenue and

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our gas marketing expense in the Condensed Statements of Income (Loss) for the three months ended September 30, 2010 and 2009 is $0.9 million and $0.6 million, respectively. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Income (Loss) for the nine months ended September 30, 2010 and 2009 is $2.0 million and $1.5 million. Firm transportation costs related to all of our Rockies Express volumes is reflected in Operating costs - oil and gas production and total $3.2 million and $3.5 million for the three months ended September 30, 2010 and 2009, respectively and $9.3 million and $8.5 million for the nine months ended September 30, 2010 and 2009, respectively.

Realized and Unrealized (Loss) Gain on Derivatives, net.

Realized and unrealized (loss) gain on derivatives, net is primarily related to derivatives for which we did not elect hedge accounting or derivatives which did not qualify for cash flow hedge accounting either at their inception or where hedge accounting was discontinued during their term. When the criteria for cash flow hedge accounting is not met, or when cash flow hedge accounting is not elected, realized gains and losses (i.e., cash settlements) are recorded in Realized and unrealized (loss) gain on derivatives, net in the Condensed Statements of Income (Loss). Similarly, changes in the fair value of the derivative instruments are recorded as unrealized gains or losses in the Realized and unrealized (loss) gain on derivatives, net in the Condensed Statements of Income (Loss). In contrast, cash settlements for derivative instruments that qualify for hedge accounting are recorded as additions to or reductions of oil and gas sales, while changes in fair value of cash flow hedges are recognized, to the extent the hedge is effective, in AOCL until the hedged item is recognized in earnings. Realized and unrealized (loss) gain on derivatives, net also includes any hedge ineffectiveness on cash flow hedges that qualify for hedge accounting.

During 2009, we entered into certain commodity derivative contracts that we did not designate as cash flow hedges. In addition, effective January 1, 2010, we elected to de-designate all of our commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. Accordingly, beginning January 1, 2010 derivative contract fair value gains and losses are recognized immediately in earnings. Cash flow is impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded to earnings under the caption Realized and unrealized (loss) gain on derivatives, net.

The following table sets forth the cash settlements and non-cash mark-to-market adjustments for the derivative contracts not designated as hedges recorded in Realized and unrealized (loss) gain on derivatives, net for the periods indicated:

	Three months ended			Nine months ended	
	September 30, 2010	**September 30, 2009**	**June 30, 2010**	**September 30, 2010**	**September 30, 2009**
			(in thousands)		
Cash receipts (payments):					
Commodity derivatives - oil	$ 2,287	$ (2,610)	$ 21	$ 1,894	$ (2,610)
Commodity derivatives - natural gas	2,342	(349)	2,757	5,617	(349)
Financial derivatives - interest	(1,812)		(1,829)	(5,466)	
Mark-to-market gain (loss):					
Commodity derivatives - oil	$ (36,502)	$ 4,176	$ 58,852	$ 15,236	$ (3,098)
Commodity derivatives - natural gas	7,121	(154)	(2,888)	16,172	(1,185)
Financial derivatives - interest	(614)		(856)	(2,971)	
	$ (27,178)	$ 1,063	$ 56,057	$ 30,482	$ (7,242)

Total Realized and unrealized gain (loss) on derivatives, net for items not under hedge accounting	

For the three and nine months ended September 30, 2009, a portion of the change in fair value for hedges that we have designated as cash flow hedges impacts our income as our sales price was not perfectly correlated with our hedges. We recognized an unrealized net loss of approximately $0.5 and $0.4 million on the Condensed Statements of Income (Loss) under the caption Realized and unrealized (loss) gain on derivatives, net for the three and nine months ended September 30, 2009. In the nine months ended September 30, 2009, we reclassified a gain of $14.3 million from AOCL to the Condensed Statements of Income (Loss) under the caption Realized and unrealized (loss) gain on derivatives, net. The $14.3 million gain was in conjunction with the first quarter 2009 sale of the DJ basin assets, in which we concluded that the forecasted transaction in certain of our hedging relationships was not probable. During the first quarter of 2009, we entered into natural gas derivatives on behalf of the purchaser of our DJ assets. We did not elect hedge accounting for these hedges and recorded an unrealized net loss of $0.5 million on the Condensed Statements of Income (Loss) under the caption (Loss) income from discontinued operations, net of taxes.

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Settlement of Flying J Bankruptcy.

On July 6, 2010, that certain Joint Plan of Reorganization of Flying J, Inc., Big West of California, LLC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United State Bankruptcy Code. Additionally, on July 6, 2010, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of our claim in Flying J s pending bankruptcy. Pursuant to the Stipulation, we and Flying J agreed that the total amount owed to us by Flying J was $60.5 million. We received $60.5 million in cash on July 23, 2010. In the quarter ended September 30, 2010, the Company recorded a settlement of its Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million. See Note 11 to the Condensed Financial Statements.

Oil and Gas Operating and Other Expenses.

The following table presents information about our continuing operating expenses for each of the three month periods ended:

	Amount per BOE			Amount (in thousands)		
	September 30, 2010	**September 30, 2009**	**June 30, 2010**	**September 30, 2010**	**September 30, 2009**	**June 30, 2010**
Operating costs oil and gas production	$ 15.01	$ 14.99	$ 15.54	$ 46,782	$ 39,195	$ 46,452
Production taxes	2.00	1.48	1.69	6,215	3,874	5,064
DD&A oil and gas production	15.84	12.81	14.62	49,367	33,502	43,703
G&A	3.98	4.09	4.07	12,399	10,686	12,155
Interest expense	5.00	5.57	5.47	15,586	14,562	16,340
Total	$ 41.83	$ 38.94	$ 41.39	$ 130,349	$ 101,819	$ 123,714

- Operating costs in the third quarter of 2010 were $46.8 million or $15.01 per BOE, compared to $39.2 million or $14.99 per BOE in the third quarter of 2009 and $46.5 million or $15.54 per BOE in the second quarter of 2010. Steam costs are the primary variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of fuel used to generate steam. The following table presents steam information:

	September 30, 2010 (3Q10)	**September 30, 2009 (3Q09)**	**3Q10 to 3Q09 Change**	**June 30, 2010 (2Q10)**	**3Q10 to 2Q10 Change**
Average volume of steam injected (Bbl/D)	112,379	110,381	2%	110,467	2%
Fuel gas cost/MMBtu (including transportation)	$ 4.16	$ 3.26	28%	$ 4.29	(3)%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	34,561	32,193	7%	33,501	3%

The increase in operating costs compared to the third quarter of 2009 is primarily due to a 28% increase in fuel gas costs as a result of an increase in natural gas prices and a 7% increase in fuel gas volume consumed in steam generation. The decrease in operating costs per BOE in the third quarter of 2010 compared to the second quarter of 2010 is due to increased production.

- Production taxes in the third quarter of 2010 were $6.2 million, or $2.00 per BOE, compared to $3.9 million, or $1.48 per BOE, in the third quarter of 2009 and $5.1 million or $1.69 per BOE in the second quarter of 2010. Severance taxes paid in Utah, Colorado and Texas are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. As the proportion of our production changes from area to area, our production tax rate will vary depending on the quantities produced from each area and the production tax rate in effect for those areas. The increase in production taxes, on a per barrel basis, compared to the third quarter of 2009 and second quarter of 2010 is due to an increase in the assessed ad valorem values attributed to our California properties.

- Depreciation, depletion and amortization (DD&A) in the third quarter of 2010 was $49.4 million, or $15.84 per BOE, compared to $33.5 million, or $12.81 per BOE, in the third quarter of 2009 and $43.7 million or $14.62 per BOE in the second quarter of 2010. The increase in DD&A in the third quarter of 2010 compared to both the third quarter of 2009 and the second quarter of 2010 is primarily due to the increase in production from assets outside of California which have higher per barrel DD&A rates than our California properties.

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• General and administrative expense (G&A) in the third quarter of 2010 was $12.4 million compared to $10.7 million in the third quarter of 2009 and $12.2 million in the second quarter of 2010. The increase from the third quarter of 2009 and the second quarter of 2010 was primarily due to an increase in employee headcount. G&A expense decreased to $3.98 per BOE in the third quarter of 2010 compared to $4.09 in the second quarter of 2010 and $4.07 in the second quarter of 2010 due to increased production.

• Interest expense in the third quarter of 2010 was $15.6 million, or $5.00 per BOE, compared to $14.6 million, or $5.57 per BOE in the third quarter of 2009 and $16.3 million, or $5.47 per BOE, in the second quarter of 2010. The increase in interest expense in the third quarter of 2010 compared to the third quarter of 2009 is due to $1.9 million, or $0.61 per BOE, of non-cash derivative losses relating to the de-designated interest rate hedges reclassed from AOCL into interest expense. Excluding the non-cash derivative loss in the third quarter of 2010, interest expense was $4.39 per BOE. The decrease in interest expense in the third quarter of 2010 compared to the second quarter of 2010 is due to a $0.5 million decrease in amortized non-cash derivative loss relating to the de-designated hedges from AOCL into interest expense.

The following table presents information about our continuing operating expenses for each of the nine month periods ended:

	Amount per BOE		Amount (in thousands)	
	September 30, 2010	September 30, 2009	September 30, 2010	September 30, 2009
Operating costs oil and gas production	$ 16.03	$ 13.91	$ 140,269	$ 111,317
Production taxes	1.88	1.80	16,484	14,411
DD&A oil and gas production	14.74	13.03	128,976	104,271
G&A	4.39	4.64	38,389	37,143
Interest expense	5.64	4.40	49,373	35,201
Total	$ 42.68	$ 37.78	$ 373,491	$ 302,343

• Operating costs in the nine months ended September 30, 2010 were $140.3 million or $16.03 per BOE, compared to $111.3 million or $13.91 per BOE in the nine months ended September 30, 2009. Steam costs are the primary variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of fuel used to generate steam. The following table presents steam information for each of the nine months periods ended:

	September 30, 2010	September 30, 2009	Change
Average volume of steam injected (Bbl/D)	113,836	106,892	6%
Fuel gas cost/MMBtu (including transportation)	$ 4.66	$ 3.44	35%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	34,881	29,308	19%

The increase in operating costs is primarily due to a 35% increase in fuel gas costs as a result of an increase in natural gas prices and a 19% increase in fuel gas volume consumed in steam generation.

• Production taxes in the nine months ended September 30, 2010 were $16.5 million, or $1.88 per BOE, compared to $14.4 million, or $1.80 per BOE in the nine months ended September 30, 2009. Severance taxes paid in Utah, Colorado and Texas are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. The increase in production taxes compared to the nine months ended September 30, 2009 is due to increased ad valorem tax values attributed to our California properties.

- Depreciation, depletion and amortization (DD&A) in the nine months ended September 30, 2010 was $129.0 million, or $14.74 per BOE, compared to $104.3 million, or $13.03 per BOE, in the nine months ended September 30, 2009. The increase in the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009 is primarily due to the increase in production from assets outside of California which have higher per barrel DD&A rates than our California properties.

- General and administrative expense (G&A) in the nine months ended September 30, 2010 was $38.4 million compared to $37.1 million in the nine months ended September 30, 2009. The increase was primarily due to an increase in employee headcount. On a per BOE basis, G&A expense decreased to $4.39 per BOE for the nine months ended September 30, 2010 compared to $4.64 per BOE for the nine months ended September 30, 2009 due to increased production.

- Interest expense in the nine months ended September 30, 2010 was $49.4 million, or $5.64 per BOE, compared to $35.2 million,

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or $4.40 per BOE, in the nine months ended September 30, 2009. The increase in interest expense compared to the nine months ended September 30, 2009 was due to the issuance of our 10.25% senior notes due 2014. The amortization of the net discount and deferred loan costs attributable to the 10.25% senior notes is also included in interest expense. Additionally, in the nine months ended September 30, 2010, we reclassified $7.0 million, or $0.80 per BOE, of non-cash derivative losses relating to de-designated interest rate hedges from AOCL into interest expense. Excluding the non-cash derivative losses, interest expense in the nine months ended September 30, 2010 was $4.84 per BOE.

Transaction costs on acquisitions. In the nine months ended September 30, 2010, we incurred $2.6 million of acquisition related expenses for the acquisition of certain properties in the Permian basin.

Dry hole, abandonment, impairment and exploration. In the three and nine months ended September 30, 2010 we incurred dry hole, abandonment, impairment and exploration expense of $0.6 million and $2.2 million, respectively, which was primarily a result of mechanical failure encountered on one well in the Piceance basin. The well was abandoned in favor of drilling a replacement well from the same well pad. During the three and nine months ended September 30, 2009, we incurred dry hole, abandonment, impairment and exploration expense of $0.1 million and $0.2 million, respectively.

Loss on discontinued operations. On March 3, 2009, we entered into an agreement to sell our DJ basin assets and related hedges for $154 million before customary closing adjustments. The closing date of the sale of our DJ basin assets was April 1, 2009. We recorded an impairment charge of $9.6 million, which is aggregated within (Loss) income from discontinued operations, net of tax, on the Condensed Statements of Income (Loss) for the nine months ended September 30, 2009.

Income Tax Expense. The effective income tax rate for the three months ended September 30, 2010 and 2009 was 20.8% and 36.2%, respectively. The effective income tax rate was 38.3% and 34.3% for the nine months ended September 30, 2010 and 2009, respectively. The decrease in the effective tax rate in the third quarter of 2010 compared to the third quarter of 2009 is due a to one-time charge recorded in 2010 for actual tax return results and the relative weight of the one-time charge to the third quarter 2010 pre-tax loss. The increase in the effective tax rate for the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009 is due to a one-time reduction in the overall state deferred tax rate in 2009 and to a one-time reduction in uncertain tax positions in 2009. The 2009 state tax rate reduction relates to acquisitions made in lower tax jurisdictions that reduced total future state tax obligations. Our estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences.

2011 Capital Outlook.

Assuming completion of the acquisitions in 2010, we plan to run four drilling rigs in the Permian basin during 2011 and spend approximately $130 million to drill approximately 75 wells. Our capital budget for 2011, based on $75 WTI, is expected to be between $375 million and $425 million and should be fully funded from cash flow. Approximately 90% of our 2011 capital expenditures is expected to be directed towards our oil assets targeting oil production growth of at least 20%. We expect our total average 2011 production to be between 37,000 and 39,000 BOED.

Drilling Activity.

The following table sets forth certain information regarding drilling activities (including operated and non-operated wells):

	Three months ended September 30, 2010		Nine months ended September 30, 2010	
Asset Team	**Gross Wells**	**Net Wells**	**Gross Wells**	**Net Wells**
S. Midway	17	17	70	69
N. Midway	16	16	33	33
Permian	9	8	14	13
Uinta	14	14	52	49
E. Texas	3	3	7	7
Piceance	5	4	14	10
Totals	64	62	190	181

Properties.

We currently have six asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including diatomite (N. Midway), Permian, Uinta, E. Texas and Piceance. Our S. Midway asset team is primarily focused on production and generates significant cash flow to fund our planned drilling inventory in our N. Midway, Permian, Uinta, E. Texas and Piceance projects.

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S. Midway This asset team is responsible for our S. Midway leases including Homebase, Formax and Ethel D, as well as our Poso Creek property. In the third quarter of 2010 we drilled 17 wells, including nine vertical producers at Poso Creek and four horizontal producers at the Formax lease. The balance of the wells were drilled for water disposal and temperature monitoring purposes. These 13 producing new wells are currently on production or under going their first steam cycle. Average daily production in the third quarter of 2010 from all S. Midway assets was approximately 11,855 BOE/D.

N. Midway Our N. Midway asset team includes our Diatomite, Placerita and McKittrick assets as well as several other N. Midway Sunset properties. Diatomite production in the third quarter of 2010 averaged 2,290 BOE/D and was impacted by a suspension of drilling activity as we worked to secure permits from the California Division of Oil, Gas and Geothermal Resources (DOGGR) as well as field optimization activities needed to resume drilling. Steam injection, which had been averaging over 30,000 BSPD earlier in the year, decreased as a result of the facility and infrastructure modifications. In September 2010, we received approval from the DOGGR for the next phase of development of our diatomite project. The first rig resumed drilling in early October 2010 and we plan to add a second drilling rig in the fourth quarter of 2010. Steam injection has steadily increased and we expect to exit 2010 at approximately 35,000 BSPD. Production from our Diatomite assets is expected to recover as we increase injection and begin adding producers. We expect approval for the balance of the project within the next six months. During the third quarter of 2010, we drilled 16 wells, including 10 wells at Placerita to initiate a steam flood pilot in the Upper Kraft. We have evaluated the performance of the McKittrick steam flood pilot, determined that this project is economic and are planning an expanded development program for 2011. Average daily production in the third quarter of 2010 from all N. Midway assets was approximately 4,865 BOE/D.

Permian Our Permian asset team executed a three rig drilling program in the third quarter of 2010 and drilled 8 new wells. Average daily production in the third quarter of 2010 was approximately 1,341 BOE/D, a 30% increase compared to the second quarter of 2010.

Uinta In the third quarter of 2010, production from our Uinta basin assets averaged 5,785 BOE/D. We drilled 14 wells during the quarter, targeting higher oil potential areas of Brundage Canyon and the Ashley National Forest. During the quarter we completed four Lake Canyon wells that were drilled earlier in the year. The wells were completed in both the Wasatch and Green River formations yielding encouraging early results. The Ashley Forest Development EIS continues to progress with approval of the final EIS anticipated within the next six months. Our drilling inventory in the Uinta is approximately 350 locations distributed between Brundage Canyon, the Ashley Forest and Lake Canyon.

E. Texas In the third quarter of 2010, production from our E. Texas assets averaged 36.1 MMcfe/D. We continued to operate a one rig program, which is drilling a horizontal Haynesville well in the Darco field located in Harrison County. In the third quarter we successfully drilled three horizontal wells and completed two horizontal wells. As of September 30, 2010 we had six Haynesville wells completed and online with results continuing to meet our expectations.

Piceance In the third quarter of 2010, production from the Piceance basin averaged 23.9 MMcfe/D. We continued to operate a one rig drilling program focusing on remaining lease earning obligations. We drilled five wells in the third quarter and continued to utilize improved completions techniques with four new well completions online in the quarter. Results from these completions continue to meet our expectations.

Financial Condition, Liquidity and Capital Resources

Our exploration, development, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and our bank credit facilities as our primary sources of liquidity. We have also used the debt and equity markets as other sources of financing and, as market conditions have permitted, we have engaged in asset monetization transactions.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flow. In total, we have approximately 75% and 60% of our expected 2010 and 2011 oil production, respectively, hedged in the form of swaps and collars. This level of derivatives is expected to provide a measure of certainty of the cash flow that we will receive for a portion of our production in 2010 and 2011. In the future, we may determine to increase or decrease our derivative positions. Most of our derivatives counterparties were commercial banks that are parties to our credit facilities, or their affiliates. See Item 3, Quantitative and Qualitative Disclosures About Market Risk for further details concerning our hedging activities.

At September 30, 2010, we had a working capital deficit of approximately $97.1 million. We generally maintain a working capital deficit due to using excess cash to reduce borrowings under our senior secured revolving credit facility. Our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

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We have a senior secured revolving credit facility with a borrowing base at September 30, 2010 of $938 million and $674 million of available borrowing capacity. At September 30, 2010, we had $240 million in borrowings and $24 million in letters of credit outstanding under the credit facility. Our borrowing base is subject to semi-annual redeterminations in April and October of each year and was reconfirmed in April 2010. The borrowing base is determined by the lenders (a syndicate of banks), taking into consideration the estimated value of our proved oil and gas reserves based on pricing models determined by the lenders. In addition, we may borrow up to $30 million for a maximum of 30 days under our Secured Line of Credit. There were no outstanding borrowings on the Secured Line of Credit at September 30, 2010 or December 31, 2009. See Note 6 to the Condensed Financial Statements.

The debt and equity markets have served as our primary source of financing to fund large acquisitions and other transactions. In January 2010, we sold to the public 8 million shares of our common stock at a price of $29.25 per share and received $224 million of net proceeds after deducting the underwriting discounts and the offering expenses. We used the net proceeds to fund the March Acquisition and to reduce our outstanding borrowings under our senior secured revolving credit facility. In May 2009, we issued $325 million principal amount of 10.25% senior notes due 2014 and in August 2009 we issued an additional $125 million principal amount of our 10.25% senior notes due 2014. See Note 6 to the Condensed Financial Statements.

Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control.

We also have engaged in asset dispositions as a means of generating additional cash to fund expenditures and enhance our financial flexibility. For example, in April 2009, we sold our DJ basin assets and related hedges for $154 million before customary closing adjustments and in July 2009 we completed the sale of our E. Texas gathering system for $18 million in cash.

Cash Flows.

Operating activities - Net cash flows provided by operating activities are primarily affected by the price of crude oil and natural gas, production volumes, and changes in working capital. The increase in net cash provided by operating activities of $170.1 million in the first nine months of 2010 compared to the first nine months of 2009 is primarily due to higher realized commodity sales prices in the first nine months of 2010 compared to the first nine months of 2009.

Investing Activities - Cash flows used by investing activities are primarily comprised of acquisition, exploration and development of oil and gas properties net of dispositions of oil and gas properties. Net cash used in investing activities in the first nine months of 2010 primarily consisted of $231.0 million of exploration and development expenditures and $154.5 million primarily attributable to the Permian Basin Acquisitions. Net cash provided by investing activities in the first nine months of 2009 primarily consisted of proceeds from the sale of the DJ basin assets in 2009.

Financing Activities - Net cash provided by financing activities in the first nine months of 2010 included proceeds from the issuance of stock of $224.3 million, offset by the net repayment of borrowings under our senior secured revolving credit facility and our Secured Line of Credit of $132.0 million and dividends paid of $12.1 million. Net cash used in financing activities in the first nine months of 2009 included the net repayment of borrowings under our senior secured revolving credit facility and our Secured Line of Credit of $566.8 million, debt issuance costs of $23.9 million and dividends paid of $10.2 million, offset by the net proceeds from the issuance of 10.25% senior notes of $435.0 million.

Capital Expenditures.

We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. In 2010, we are expecting a capital program of up to $290 million to $310 million, and we expect to fully fund this program from operating cash flow. Our capital expenditures for the third quarter of 2010 totaled $95.9 million for development and capitalized interest of $7.3 million. Our capital expenditures for the nine months ended September 30, 2010 totaled $231.0 million for development and capitalized interest of $20.4 million compared to total capital expenditures for the nine months ended September 30, 2009 of $94.6 million for development and capitalized interest of $21.1 million. We expect our 2010 capital program will allow us to increase production from 2009 levels to average 2010 production between 32,250 BOE/D and 33,000 BOE/D.

We believe that our cash flow provided by operating activities and funds available under our credit facilities will be sufficient to fund our operating and capital expenditures budget and our short-term contractual operations during 2010. However, if our revenue and cash flow decrease in the future as a result of deterioration in economic conditions or an adverse change in commodity prices, we

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may have to reduce our spending levels. As we have operational control of all of our assets and we have limited drilling commitments, we believe that we have the financial flexibility to adjust our spending levels, if necessary, to meet our financial obligations.

Critical Accounting Policies and Estimates.

Reference should be made to the corresponding section in Part II, Item 7 of our Annual Report on Form 10-K, as amended, for the year ended December 31, 2009 for a discussion of other critical accounting policies that we consider as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We also enter into derivative contracts to mitigate the risk of interest rate fluctuations. The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in AOCL until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the Condensed Statements of Income because changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative s fair value and any ineffective portion of the derivative instrument s change in fair value is recognized immediately in earnings. The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, whether or not the forecasted hedged transaction will occur, option pricing models, futures prices, volatility, time to maturity and credit risk. The values we report in our Condensed Financial Statements changes as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. Effective January 1, 2010, we have elected to de-designate all of our commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. At December 31, 2009, AOCL consisted of $97 million ($60 million after tax) of unrealized losses, representing the fair value of our cash flow hedges as of the Condensed Balance Sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such changes in fair values at December 31, 2009 are frozen in AOCL as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions affect earnings. We expect to reclassify into earnings from AOCL the frozen value related to de-designated commodity hedges during the next three years. See Note 8 to the Condensed Financial Statements.

Recent Accounting Standards and Updates.

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-06 *Improving Disclosures about Fair Value Measurements.* The ASU amends previously issued authoritative guidance and requires new disclosures and clarifies existing disclosures and is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the rollforward activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. As this requires only additional disclosures, the guidance will have no impact on our financial position or results of operations.

Reconciliation of Non-GAAP Measures.

Discretionary Cash Flow

In addition to reporting cash provided by operating activities as defined under GAAP, we present discretionary cash flow, which is a non-GAAP liquidity measure. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items. Management uses discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. The following table provides a reconciliation of cash provided by operating activities, the most directly comparable GAAP measure, to adjusted discretionary cash flow for the period presented.

(in millions)	For the Nine Months Ended September 30, 2010	For the Three Months Ended September 30, 2010
Net cash provided by operating activities	$ 318.5	$ 183.6
Add back: Net decrease in current assets	(19.9)	(53.0)
Add back: Net increase in current liabilities including book overdraft	(30.4)	(35.9)
Add back: Recovery of Flying J bad debt	38.5	
Discretionary cash flow	$ 306.7	$ 94.7

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Berry Petroleum Company

Quantitative and Qualitative Disclosures About Market Risk

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 8 to the Condensed Financial Statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas derivative contracts from time to time. The terms of contracts depend on various factors, including management s view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. In California, we benefit from lower natural gas pricing, as we are a consumer of natural gas in our operations, and elsewhere we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate and in accordance with policy established by our board of directors. Currently, our derivatives are in the form of swaps and collars. However, we may use a variety of derivative instruments in the future to hedge WTI or the index gas price. A two-way collar is a combination of options, a sold call and purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options, a sold call, a purchased put and a sold put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. We utilize costless collars which is an options position by which the proceeds from the sale of the call option fund the purchase of a put option.

In total, we have approximately 75% and 60% of our expected 2010 and 2011 oil production, respectively, hedged in the form of swaps and collars. A ten dollar change in oil prices impacts our annual operating cash flow by approximately $7 million. In 2010, a one dollar change in natural gas prices impacts annual operating cash flow by approximately $1 million.

The following table summarizes our commodity derivative position as of September 30, 2010:

Term	Average Barrels Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Two-Way Collars		
Full year 2010	1,000	$65.15 / $75.00
Full year 2010	1,000	$65.50 / $78.50
Full year 2010	280	$80.00 / $90.00
Full year 2010	1,000	$100.00/$161.10
Full year 2010	1,000	$100.00/$150.30
Full year 2010	1,000	$100.00/$160.00
Full year 2010	1,000	$100.00/$150.00
Full year 2010	1,000	$100.00/$158.50
Full year 2010	1,000	$70.00/$86.00
Full year 2010	500	$75.00/$93.95
Full year 2010	500	$75.00/$94.45

Full year 2011	270	$80.00 / $90.00
Full year 2011	1,000	$55.20/$70.00
Full year 2011	1,000	$55.00 / $70.50
Full year 2011	1,000	$55.00/$68.65
Full year 2011	1,000	$55.00/$68.00
Full year 2011	1,000	$55.00/$71.20
Full year 2011	1,000	$60.00/$76.00
Full year 2011	1,000	$60.00/$81.25
Full year 2011	500	$75.00/$100.75
Full year 2011	500	$75.00/$101.15
Full year 2011	1,000	$75.00/$91.25
Full year 2012	1,000	$63.00/$82.60
Full year 2012	1,000	$63.00/$83.50
Full year 2012	1,000	$70.00/$93.00

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Full year 2012	500	$75.00/$105.00
Full year 2012	500	$75.00/$106.00
Full year 2012	1,000	$75.00/$95.00
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2011	1,000	$60.00/$80.00/$101.00
Full year 2011	1,000	$55.00/$75.00/$91.63
Full year 2011	500	$65.00/$85.00/$97.25
Full year 2011	1,000	$69.70/$85.00/$100.00
Full year 2011	1,000	$70.00/$86.85/$100.00
Full year 2012	1,000	$60.00/$80.00/$120.00
Full year 2012	1,000	$65.00/$85.00/$97.25
Full year 2012	1,000	$60.00/$80.00/$96.92
Full year 2012	1,000	$70.00/$86.85/$100.00
Full year 2012	1,000	$69.70/$85.00/$100.00
Full year 2013	1,000	$65.00/$85.00/$97.25
Full year 2013	1,000	$60.00/$80.00/$103.30
Full year 2013	1,000	$70.00/$86.85/$100.00
Full year 2013	1,000	$69.70/$85.00/$100.00
Crude Oil Sales (NYMEX WTI) Swaps		
Full year 2010	1,000	$61.00
Full year 2010	1,000	$61.25
Full year 2010	1,000	$64.80
Full year 2010	1,000	$62.03
Full year 2010	1,000	$63.00
Full year 2010	1,000	$63.75
Full year 2010	650	$56.90
Full year 2011	500	$57.36
Full year 2011	500	$57.40
Full year 2011	500	$57.50
Full year 2011	250	$61.80
Natural Gas Sales (NYMEX HH) Two-way Collars		
Full year 2010	2,000	$6.00/$8.60
Full year 2010	3,000	$6.00/$8.65
Full year 2010	1,000	$6.50/$8.75
Full year 2010	1,000	$6.50/$8.85
Full year 2010	2,000	$6.50/$8.90
Full year 2011	5,000	$6.00/$7.25
Full year 2012	5,000	$6.00/$7.70
Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
Full year 2010	2,000	$1.05
Full year 2010	3,000	$1.00
Natural Gas Sales (NYMEX HH TO NGPL) Basis Swaps		
Full year 2010	2,000	$0.49
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2010	2,000	$0.38
Full year 2010	2,500	$0.35
Full year 2011	2,500	$0.33
Full year 2012	2,500	$0.32
Natural Gas Sales (NYMEX HH TO NGPL-Tex OK) Basis Swaps		

Full year 2010	2,500	$0.42
Full year 2011	2,500	$0.46
Full year 2012	2,500	$0.44

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Natural Gas Sales (NYMEX HH) Swaps		
Full year 2010	5,000	$5.73
Full year 2010	5,000	$6.02
Full year 2011	5,000	$5.50
Full year 2011	5,000	$6.89
Full year 2012	5,000	$5.75
Full year 2012	5,000	$7.16

Based on average NYMEX futures prices as of September 30, 2010 (WTI $86.09; HH $4.69) for the term of our derivatives we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas derivatives in place as follows:

	September 30, 2010 NYMEX Futures	Impact of percent change in futures prices on pre-tax future cash (payments) and receipts -40%	-20%	+ 20%	+40%
Average WTI Futures Price (2010 2013)	$ 86.09	$ 51.65	$ 68.87	$ 103.31	$ 120.52
Average HH Futures Price (2010 2012)	4.69	2.81	3.75	5.63	6.57
Crude Oil gain/(loss) (in millions)	$ (54.6)	$ 198.8	$ 83.4	$ (183.4)	$ (382.8)
Natural Gas gain/(loss) (in millions)	23.7	55.9	40.5	10.5	(1.8)
Total	$ (30.9)	$ 254.7	$ 123.9	$ (172.9)	$ (384.6)
Net pre-tax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2010 (WTI $80.40; HH $3.99)	(1.8)	48.5	22.0	(24.3)	(44.1)
2011 (WTI $84.35; HH $4.47)	(35.7)	89.5	36.5	(109.5)	(206.4)
2012 (WTI $87.12; HH $5.08)	6.6	91.2	45.4	(30.8)	(100.0)
2013 (WTI $88.22)		25.5	20.0	(8.3)	(34.1)
Total	$ (30.9)	$ 254.7	$ 123.9	$ (172.9)	$ (384.6)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued, in a public offering, $200 million principal amount of 8.25% senior subordinated notes due 2016. In May 2009, we issued, in a public offering, $325 million of 10.25% senior notes due 2014. In August 2009, we issued, in a public offering, an additional $125 million of 10.25% senior notes due 2014. At September 30, 2010, total long-term debt outstanding was $878.3 million, net of unamortized discount of $11.7 million on our notes. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 2.25% to 3.0%, plus an annual commitment fee on the unused portion of the credit facility of 0.50%. Based on September 30, 2010 credit facility borrowings, a 1% change in interest rates, including our interest rate derivatives, would not impact on our Condensed Financial Statements.

We have entered into interest rate derivatives as shown below to swap the floating rate under our senior secured credit facility (LIBOR) for a fixed interest rate.

Derivative Term	Notional Amount $MM	Fixed Rate
4/1/2009 6/30/2012	100	4.74%
4/15/2009 7/15/2012	100	1.99%

9/15/2009	7/15/2012	50	2.31%

As of September 30, 2010, as a result of our interest rate derivative contracts and the Notes, we have a total of $900 million of fixed rate positions averaging 7.8%.

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Controls and Procedures

Item 4. Controls and Procedures

As of September 30, 2010, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended.

Based on their evaluation as of September 30, 2010, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and include controls and procedures designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There was no change in our internal control over financial reporting that occurred during the three months ended September 30, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

Forward Looking Statements

Safe harbor under the Private Securities Litigation Reform Act of 1995: Any statements in this Form 10-Q that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as plan, will, intend, continue, target(s), expect, achieve, may, could, goal(s), anticipate, estimate or other comparable words or phrases, or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management s current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 17 of our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 25, 2010, under the heading Risk Factors and all material changes are updated in Part II, Item 1A within this Form 10-Q.

Berry Petroleum Company

PART II Other Information

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We received a notice of violation from the San Joaquin Valley Unified Air Pollution Control District (the District) alleging that we failed to properly operate several diesel powered portable pumps in compliance with the District s regulations. We entered into negotiations with the District. While we deny any wrongdoing, on September 28, 2010, we entered into a settlement with the District and paid $123,600 in full satisfaction of the matter.

Item 1A. Risk Factors

For additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 25, 2010.

The future of the electricity market in California is uncertain. We utilize cogeneration plants in California to generate lower cost steam compared to conventional steam generation methods. Electricity produced by our cogeneration plants is sold to utilities and the steam costs are allocated to our oil and natural gas operations. On October 7, 2010, we executed agreements with Pacific Gas and Electric Company (PG&E), which, if approved by the California Public Utilities Commission (CPUC), will extend the electricity sales contracts for our 18MW and 38MW facilities until June 30, 2011. Our electricity sales contracts with Southern California Edison Company (Edison) for our Placerita facility will continue in effect until the CPUC approves and makes available replacement standard form Qualifying Facilities (QF) contracts, which, under the pending settlement agreement described below, will likely be sometime in 2011; however, our current contracts could terminate earlier under certain limited circumstances. Additionally, legal and regulatory decisions (especially related to the pricing of electricity under the contracts such as the SRAC Decision (as defined in our Annual Report on Form 10-K for the year ended December 31, 2009) and the pending issues as to effective dates on retroactivity), can by reducing our electricity revenues adversely affect the economics of our cogeneration facilities and as a result the cost of steam for use in our oil and natural gas operations. In addition, any final determination by the CPUC to apply the new SRAC pricing formula retroactively, if applied so as to require payment on a one-time basis, could have a material adverse effect on our financial condition and results of operations. During the California energy crisis in 2000 and 2001, we had electricity sales contracts with various utilities and a portion of the electricity prices paid to us under such contracts from December 2000 to March 27, 2001 has been under a degree of legal challenge since that time. There are ongoing proceedings before the CPUC in which Edison and PG&E are seeking credit against future payments they are to make for electricity purchases based on retroactive adjustments to pricing under contracts with us. It is possible that we may have a liability pending the final outcome of the CPUC proceedings on the matter. Whether or not retroactive adjustments will be ordered, how such adjustments would be calculated and what period they would cover are too uncertain to estimate at this time. On October 8, 2010, a settlement agreement was filed at the CPUC by and between the three California utilities, two consumer representative groups and three parties that represent the interests of the majority of the cogeneration facilities in the state, including us, that if adopted by the CPUC, would extinguish all pending claims of retroactive payment liability. A ruling on this settlement is expected later this year or during the early part of 2011. However, it is possible that the CPUC may not approve such settlement. See Item 1. Business Electricity of our Annual Report on Form 10-K for the year ended December 31, 2009 for more information about our electricity sales contracts.

Climate change legislation or regulatory initiatives may adversely affect our operations, our cost structure, and the demand for the oil and natural gas that we produce. On December 15, 2009, the U.S. Environmental Protection Agency (EPA) published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) present an endangerment to public heath and the environment because emissions of such gasses are, according to the EPA, contributing to the warming of the earth s atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards take effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V permitting programs. This rule tailors these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to best available control technology standards for GHG that have yet to be developed. More recently, on August 12, 2010, the EPA proposed additional regulatory actions to provide for implementation of these permitting requirements by state environmental agencies or by the EPA on their behalf. With regards to the monitoring and reporting of GHGs, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. In addition, on April 10, 2010, the EPA published a proposed rule that would expand its existing GHG reporting rule to include onshore petroleum and natural gas production, processing, transmission storage and distribution facilities. If the proposed rule is finalized as proposed, reporting of GHG emissions from such facilities would be required on an annual basis, with reporting beginning in 2012 for emission occurring in 2011.

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Similarly, the House of Representatives and Senate have been considering adoption of cap and trade legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission allowances corresponding to their annual emissions of GHGs. At the state level, almost one-half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. The State of California has adopted legislation that caps California s GHG emissions at 1990 levels by 2020, and the California Air Resources Board (CARB) has implemented mandatory reporting regulations and is proceeding with early action measures to reduce GHG emissions prior to January 1, 2012. CARB is also developing regulations to implement a cap and trade program in 2012 to reduce GHG emissions. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas that we produce.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Congress is currently considering two companions bills for the Fracturing Responsibility and Awareness of Chemicals Act (FRAC Act). The bills would repeal an exemption in the federal Safe Drinking Water Act (SWDA) for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of the FRAC Act have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Further, if enacted, the FRAC Act could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of any future federal or state laws or implementing regulation imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing, complete natural gas wells in shale formations and increase our costs of compliance and doing business.

The recent adoption of derivatives legislation by Congress could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any

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of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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

Exhibit No.	Description of Exhibit
10.1*	Crude Oil Purchase Contract dated October 5, 2010 between the Registrant and ExxonMobil Oil Corporation.
12.1	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document**
101.SCH	XBRL Taxonomy Extension Schema Document**
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document**
101.LAB	XBRL Taxonomy Label Linkbase Document**
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document**
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document**

* Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

** Furnished herewith.

SIGNATURE

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 thereto duly authorized.

BERRY PETROLEUM COMPANY

/s/ Jamie L. Wheat
Jamie L. Wheat
Controller
(Principal Accounting Officer)
Date: October 27, 2010