BERRY PETROLEUM CO
Form 10-Q
November 03, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2011

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 ý 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 ý 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 ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of October 21, 2011 the registrant had 51,860,811 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 21, 2011, all of which is held by an affiliate of the registrant.

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BERRY PETROLEUM COMPANY

Condensed Balance Sheets

(Unaudited)

(In Thousands, Except Share Information)

	September 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 94	$ 278
Restricted short-term investments	65	65
Accounts receivable	116,859	93,406
Deferred income taxes	1,783	32,342
Derivative instruments	41,055	2,742
Prepaid expenses and other	16,296	14,033
Total current assets	176,152	142,866
Oil and gas properties (successful efforts basis), buildings and equipment, net	3,076,894	2,655,792
Derivative instruments	34,703	2,054
Other assets	31,462	37,904
	$ 3,319,211	$ 2,838,616
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 122,349	$ 106,459
Revenue and royalties payable	40,209	37,812
Accrued liabilities	52,985	36,234
Line of credit	17,500	5,300
Derivative instruments	3,444	84,846
Deferred income taxes	535	
Total current liabilities	237,022	270,651
Long-term liabilities:		
Deferred income taxes	421,396	329,207
Senior secured revolving credit facility	485,000	170,000
8.25% Senior subordinated notes due 2016	200,000	200,000
10.25% Senior notes due 2014, net of unamortized discount of $7,227 and $11,035, respectively	351,729	438,965
6.75% Senior notes due 2020	300,000	300,000
Asset retirement obligation	61,711	53,443
Derivative instruments		33,526
Other long-term liabilities	17,980	18,271
	1,837,816	1,543,412
Shareholders' equity:		
Preferred stock, $0.01 par value, 2,000,000 shares authorized; no shares outstanding		
Capital stock, $0.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 51,860,811 and 51,426,232 shares issued and outstanding, respectively	519	514
Class B Stock, 3,000,000 shares authorized;1,797,784 shares issued and outstanding (liquidation preference of $0.50 per share)	18	18
Capital in excess of par value	344,345	327,369

Accumulated other comprehensive loss		(15,157)		(43,806)
Retained earnings		914,648		740,458
Total shareholders' equity		1,244,373		1,024,553
	$	3,319,211	$	2,838,616

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

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BERRY PETROLEUM COMPANY

Condensed Statements of Operations

(Unaudited)

(In Thousands, Except Per Share Data)

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
REVENUES				
Sales of oil and gas	$ 225,325	$ 151,671	$ 643,474	$ 451,003
Sales of electricity	9,826	9,451	24,202	27,313
Gas marketing	3,612	4,918	11,282	18,194
Settlement of Flying J bankruptcy claim				21,992
Interest and other income, net	463	362	1,394	2,320
	239,226	166,402	680,352	520,822
EXPENSES				
Operating costs oil and gas production	61,979	46,782	177,842	140,269
Operating costs electricity generation	6,965	7,220	19,969	24,729
Production taxes	9,185	6,215	24,926	16,484
Depreciation, depletion & amortization oil and gas production	54,581	49,367	158,657	128,976
Depreciation, depletion & amortization electricity generation	487	819	1,479	2,407
Gas marketing	3,285	4,067	10,475	16,209
General and administrative	14,922	12,399	47,123	38,389
Interest	19,928	15,586	53,295	49,373
Dry hole, abandonment, impairment and exploration	196	586	619	2,221
Gain on purchase			(1,046)	
Transaction costs on acquisitions				2,635
Extinguishment of debt	14,391		14,391	
Realized and unrealized (gain) loss on derivatives, net	(162,145)	27,178	(126,437)	(30,482)
Bad debt recovery				(38,508)
	23,774	170,219	381,293	352,702
Earnings (loss) before income taxes	215,452	(3,817)	299,059	168,120
Income tax provision (benefit)	81,451	(794)	112,389	64,450
Net earnings (loss)	$ 134,001	$ (3,023)	$ 186,670	$ 103,670
Basic net earnings (loss) per share	$ 2.45	$ (0.06)	$ 3.42	$ 1.94
Diluted net earnings (loss) per share	$ 2.42	$ (0.06)	$ 3.38	$ 1.93
Dividends per share	$ 0.080	$ 0.075	$ 0.230	$ 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, 2011	Nine Months Ended September 30, 2010
Cash flows from operating activities:		
Net earnings	$ 186,670	$ 103,670
Depreciation, depletion and amortization	160,136	131,383
Gain on purchase	(1,046)	
Extinguishment of debt	3,377	
Amortization of debt issuance costs and net discount	6,261	6,383
Dry hole and impairment	316	1,477
Derivatives	(139,683)	(8,999)
Stock-based compensation expense	7,451	7,134
Deferred income taxes	105,096	67,533
Other, net	1,646	
Cash paid for abandonment	(1,921)	(1,830)
Bad debt recovery		(38,508)
Change in book overdraft	5,359	8,309
Changes in operating assets and liabilities:		
Accounts receivable	(24,614)	28,224
Inventories, prepaid expenses, and other current assets	(2,263)	(8,373)
Accounts payable and revenue and royalties payable	48,438	5,388
Accrued interest and other accrued liabilities	16,667	16,730
Net cash provided by operating activities	371,890	318,521
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(424,144)	(230,955)
Property acquisitions	(155,443)	(154,517)
Capitalized interest	(24,236)	(20,402)
Net cash used in investing activities	(603,823)	(405,874)
Cash flows from financing activities:		
Proceeds from issuances on line of credit	368,100	219,200
Repayments of borrowings under line of credit	(355,900)	(219,200)
Repurchase of 10.25% Senior notes due 2014	(91,044)	
Long-term borrowings under credit facility	529,400	165,000
Repayments of long-term borrowings under credit facility	(214,400)	(297,000)
Financing obligation	(281)	(257)
Debt issuance costs	(1,176)	
Dividends paid	(12,480)	(12,127)
Proceeds from issuance of common stock, net		224,313
Proceeds from stock option exercises	7,333	1,762
Excess income tax benefit	2,197	405
Net cash provided by financing activities	231,749	82,096

Net decrease in cash and cash equivalents		(184)		(5,257)
Cash and cash equivalents at beginning of period		278		5,311
Cash and cash equivalents at end of period	$	94	$	54
Noncash investing activities:				
Accrued capital expenditures	$	19,162	$	25,230
Asset retirement obligation		6,477		2,825

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 Loss	Total Shareholders' Equity
Balances at December 31, 2010	$ 514	$ 18	$ 327,369	$ 740,458	$ (43,806)	$ 1,024,553
Stock options and restricted stock issued	5		7,328			7,333
Stock based compensation expense			7,451			7,451
Income tax effect of stock option exercises			2,197			2,197
Dividends ($0.23 per share)				(12,480)		(12,480)
Comprehensive earnings:						
Net earnings				186,670		186,670
Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income tax benefit of ($17,559)					28,649	28,649
Total comprehensive earnings						215,319
Balances at September 30, 2011	$ 519	$ 18	$ 344,345	$ 914,648	$ (15,157)	$ 1,244,373

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

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements

(Unaudited)

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 fairly state Berry Petroleum Company's (the Company) Condensed Financial Statements have been included herein. 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, 2010. 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.

Certain amounts in the prior year financial statements have been reclassified to conform to the 2011 financial statement presentation. The Company increased Comprehensive earnings for the three months ended March 31, 2010 by $6.8 million to reflect the correction of a prior period error. The Company has concluded that the presentation error was immaterial to the previously filed 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, 2011 and December 31, 2010 are $21.6 million and $16.3 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Recent Accounting Standards

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04 *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in US GAAP and IFRSs.* The ASU amends previously issued authoritative guidance and is effective for interim and annual periods beginning after December 15, 2011. The amendments change requirements for measuring fair value and disclosing information about those measurements. Additionally, the ASU clarifies the FASB's intent regarding the application of existing fair value measurement requirements and changes certain principles or requirements for measuring fair value or disclosing information about its measurements. For many of the requirements, the FASB does not intend the amendments to change the application of the existing Fair Value Measurements guidance. This guidance will not have an impact on the Company's financial position or results of operations.

In June 2011, the FASB issued ASU No. 2011-05 *Presentation of Comprehensive Income.* The ASU amends previously issued authoritative guidance and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. These amendments remove the option under current U.S. GAAP to present the components of other comprehensive income as part of the statements of changes in stockholder's equity. The adoption of this guidance will not have an impact on

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

1. Basis of Presentation (Continued)

the Company's financial position or results of operations, but will require the Company to present the statements of comprehensive income separately from its statements of equity, as these statements are currently presented on a combined basis.

2. Acquisitions

On May 25, 2011, the Company acquired interests in producing properties on approximately 6,000 net acres in the Wolfberry trend in the Permian for an aggregate purchase price of $128 million (the Wolfberry Acquisition). The Wolfberry Acquisition had an effective date of March 1, 2011, with operations from March 1, 2011 through May 24, 2011 resulting in purchase price adjustments. The acquisition was financed using the Company's senior secured revolving credit facility (Credit Agreement). The Company operates 98% of and has an average 93% working interest (70% net revenue interest) in the properties acquired in the Wolfberry Acquisition.

The Company has not presented pro forma information for the properties acquired in the Wolfberry Acquisition, as the impact of the acquisition was insignificant to the Condensed Statements of Operations for the three and nine months ended September 30, 2011. Revenues of $4.2 million and $5.2 million from properties acquired in the Wolfberry Acquisition have been included in the accompanying Condensed Statements of Operations for the three and nine months ended September 30, 2011, respectively, and earnings from the acquired properties were insignificant.

The following table summarizes the consideration paid to the sellers and the amounts of the assets acquired and liabilities assumed in the Wolfberry Acquisition:

	(in thousands)
Consideration paid to sellers:	
Cash consideration	$ 128,366
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed and undeveloped properties	128,665
Asset retirement obligation	(119)
Other liabilities assumed	(180)
Total identifiable net assets	$ 128,366

In March, April and November 2010, the Company completed three separate acquisitions of producing properties located in the Wolfberry trend in the Permian for an aggregate purchase price of approximately $327 million (the Permian Acquisitions). The Permian Acquisitions were financed with net proceeds from the issuance of 8 million shares of the Company's Class A Common Stock in January 2010, cash generated from operations and net proceeds from the issuance of $300 million aggregate principal amount of the Company's 6.75% senior notes due in November 2020 (2020 Notes) in November 2010.

In the first quarter of 2011, the Company recorded a $1.0 million gain (net of deferred income taxes of $0.7 million) in conjunction with usual and customary post-closing adjustments to the purchase

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

2. Acquisitions (Continued)

price of the November 2010 Permian acquisition. The gain was recorded in the Condensed Statements of Operations under the caption Gain on purchase.

The following table summarizes the consideration paid to the sellers and the amounts of the assets acquired and liabilities assumed in the Permian Acquisitions:

		(in thousands)
Consideration paid to sellers:		
Cash consideration	$	327,032
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved developed and undeveloped properties		332,214
Other assets acquired		342
Asset retirement obligation		(3,498)
Deferred income tax liability		(647)
Other liabilities assumed		(333)
Total identifiable net assets	$	328,078

The Wolfberry Acquisition and the Permian Acquisitions qualify as business combinations and, as such, the Company estimated the fair value of each property as of each 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 based on an income approach 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. Due to the unobservable nature of the inputs, business combinations are deemed to use Level 3 inputs.

3. Debt

Short-Term Line of Credit

The Company has an unsecured uncommitted money market line of credit (Line of Credit) with a borrowing capacity of up to $40.0 million for a maximum of 30 days. As of September 30, 2011 and December 31, 2010 there were $17.5 million and $5.3 million in outstanding borrowings under the Line of Credit, respectively. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1.4%. The outstanding borrowings under the Line of Credit at September 30, 2011 and December 31, 2010 had weighted average interest rates of 1.8% and 1.7%, respectively.

Senior Secured Revolving Credit Facility

In April 2011, the Company entered into an amendment to its Credit Agreement (the Amendment). The Amendment extended the maturity date of the Credit Agreement to May 13, 2016 and increased the borrowing base from $875 million to $1.4 billion. Lender commitments remained

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

3. Debt (Continued)

unchanged at $875 million at the time of the amendment. In addition, the Amendment reduced (i) the LIBOR margin to between 1.50% and 2.50% based on the ratio of credit outstanding to the borrowing base, (ii) the prime rate margin to between 0.50% and 1.50% based on the ratio of credit outstanding to the borrowing base, and (iii) the annual commitment fee on the unused portion of the Credit Agreement to between 0.35% and 0.50%. The Amendment also provides the right for the Company to refinance its 10.25% senior notes due in 2014 (2014 Notes) and its 8.25% senior notes due in 2016 (2016 Notes) with similar notes or to retire the 2014 Notes or the 2016 Notes using available borrowings under the Credit Agreement subject to certain leverage and liquidity tests. In August 2011, the Company obtained an additional $100 million of lender commitments under its Credit Agreement, increasing total lender commitments to $975 million. Total fees paid for the August commitment increase were $0.5 million, and will be amortized over the remaining term of the Credit Agreement. On October 26, 2011, as part of the semi-annual borrowing base redetermination process, the Company entered into a third amendment to the Credit Agreement, increasing total lender commitments to $1.2 billion. See Note 12 to the Condensed Financial Statements.

As of September 30, 2011 and December 31, 2010, there were $485 million and $170 million, respectively, in outstanding borrowings under the Credit Agreement. Total outstanding debt at September 30, 2011 under the Line of Credit and Credit Agreement was $503 million, and $24 million in letters of credit have been issued under the Credit Agreement, leaving $448 million in borrowing capacity available.

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 natural gas reserves in April and October of each year in accordance with the lenders' customary procedures and practices. The Company and the banks each have the unilateral right to one additional redetermination each year. The Credit Agreement is collateralized by the Company's oil and natural gas properties.

The Credit Agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. The Credit Agreement contains covenants which, among other things, require the Company to maintain the following ratios: (i) an interest coverage ratio, as defined in the credit agreement, of 2.75 to 1.0 and (ii) a minimum current ratio, as defined in the Credit Agreement, of 1.0 to 1.0. The Company is currently in compliance with all financial covenants and has complied with all financial covenants for all prior periods.

10.25% Senior Notes Due 2014

In May 2009, the Company issued in a public offering $325 million principal amount of 10.25% senior notes due 2014 ($325 million Notes) at a discount of 93.546%. In August 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) at a premium of 104.75%. These $125 million Notes and the $325 million Notes are treated as a single series of debt securities (10.25% Notes) and are carried on the Condensed Balance Sheet at their combined amortized cost.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

3. Debt (Continued)

In August and September 2011, the Company repurchased $91.0 million aggregate principal amount of its 10.25% Notes for an aggregate purchase price of $104.5 million, including accrued and unpaid interest. The related loss of $14.4 million recorded in Extinguishment of debt consists of $11.0 million in premium paid over par and $3.4 million in write-offs of net discount and debt issuance costs. These notes were repurchased using available borrowings under the Credit Agreement. The Company also repurchased an additional $3.7 million aggregate principal amount of 10.25% Notes in October 2011. See Note 12 to the Condensed Financial Statements.

4. Income Taxes

The effective income tax rate for the three months ended September 30, 2011 and 2010 was 37.8% and 20.8%, respectively. The lower effective income tax rate in the three months ended September 30, 2010 is primarily due to a 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 effective income tax rate for the nine months ended September 30, 2011 and 2010 was 37.6% and 38.3%, respectively. The Company's estimated annual effective income tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences (*i.e.*, differences between book earnings and tax earnings that are not expected to reverse in future periods).

As of September 30, 2011, the Company had a gross liability for uncertain income tax benefits of $5.2 million, which if recognized would affect the effective income tax rate. There have been no significant changes to the calculation of uncertain income tax benefits during 2011. Consistent with the Company's policy, interest and penalties on income taxes have been recorded as a component of the Income tax provision (benefit). The Company estimates that it is reasonably possible that the balance of unrecognized income tax benefits as of September 30, 2011 could decrease by a maximum of $1.9 million in the next 12 months due to the expiration of statutes of limitation and audit settlements.

5. Earnings (Loss) Per Share and Comprehensive Earnings

Basic earnings (loss) per share is calculated by dividing earnings (loss) available to common shareholders by the weighted average shares outstanding-basic during each period. Diluted earnings (loss) per share is calculated by dividing earnings (loss) available to common shareholders by the weighted average shares outstanding-dilutive, which includes the effect of potentially dilutive securities. Potentially dilutive securities consist of unvested restricted stock awards and outstanding stock options.

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 (loss) per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Unvested 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, and thus are classified as participating securities. Participating securities do not have a contractual obligation to share in the Company's losses. Therefore, in periods of net loss, no portion of the loss is allocated to participating securities. Unvested restricted stock issued subsequent to January 1, 2010 under the Company's equity incentive plans does

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

5. Earnings (Loss) Per Share and Comprehensive Earnings (Continued)

not participate in dividends. Stock options issued under the Company's equity incentive plans do not participate in dividends. No potential shares of common stock are included in the computation of any diluted per share amount when a net loss exists.

The following table shows the computation of basic and diluted earnings (loss) per share for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands, except per share data)	**2011**	**2010**	**2011**	**2010**
Net earnings (loss)	$ 134,001	$ (3,023)	$ 186,670	$ 103,670
Less: earnings allocable to participating securities	1,207		1,797	2,011
Earnings (loss) available for common shareholders	$ 132,794	$ (3,023)	$ 184,873	$ 101,659
Basic earnings (loss) per share	$ 2.45	$ (0.06)	$ 3.42	$ 1.94
Diluted earnings (loss) per share	$ 2.42	$ (0.06)	$ 3.38	$ 1.93
Weighted average shares outstanding basic	54,211	53,007	54,029	52,357
Add: Dilutive effects of stock options and RSUs	654		743	386
Weighted average shares outstanding dilutive	54,865	53,007	54,772	52,743

All options to purchase shares were included in the diluted earnings (loss) per share calculation for the three and nine months ended September 30, 2011. Options to purchase 2.2 million shares and 1.2 million shares were not included in the diluted earnings (loss) per share calculation for the three and nine months ended September 30, 2010, respectively, because their effect would have been anti-dilutive.

Comprehensive Earnings

Comprehensive earnings is a term used to refer to net earnings plus other comprehensive earnings. Other comprehensive earnings are comprised of revenues, expenses, gains, and losses that, under GAAP, are reported as separate components of shareholders' equity instead of net earnings. The components of other comprehensive earnings were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2011**	**2010**	**2011**	**2010**
Net earnings (loss)	$ 134,001	$ (3,023)	$ 186,670	$ 103,670
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income tax benefits of ($5,886), ($2,694), ($17,559), and ($7,283), respectively	9,604	4,395	28,649	11,839
Comprehensive earnings	$ 143,605	$ 1,372	$ 215,319	$ 115,509

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

6. Asset Retirement Obligation

The following table summarizes the activity for the Company's asset retirement obligation (ARO) for the nine months ended September 30, 2011 and 2010:

	Nine Months Ended September 30,	
(in thousands)	**2011**	**2010**
Beginning balance at January 1	$ 53,443	$ 43,487
Liabilities incurred	2,169	2,825
Liabilities settled	(1,921)	(1,830)
Liabilities assumed	119	3,309
Accretion expense	3,593	3,370
Revisions in estimated cash flows	4,308	
Ending balance at September 30	$ 61,711	$ 51,161

ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and natural gas properties. Inherent in the fair value calculation of 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 natural gas property balance.

7. Equity Incentive Compensation Plans

Stock-based compensation is measured at the grant date based on the value of the awards, and the fair value is recognized on a straight-line basis over the requisite service period (generally the vesting period).

Total compensation cost recognized in the Statements of Operations for the grants under the Company's equity incentive compensation plans was $1.9 million and $2.0 million during the three months ended September 30, 2011 and 2010, respectively, and $7.0 million and $6.1 million during the nine months ended September 30, 2011 and 2010, respectively.

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

7. Equity Incentive Compensation Plans (Continued)

Stock Options

The following table summarizes stock option activity for the nine months ended September 30, 2011:

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)(1)	Number of Shares Exercisable
Outstanding at January 1, 2011	2,017,225	$ 25.87	$ 35,974	1,884,937
Granted	89,865	48.50		
Exercised	(415,885)	17.66		
Cancelled/expired	(6,765)	45.92		
Outstanding at September 30, 2011	1,684,440	$ 29.02	$ 13,991	1,558,886

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock at the end of the related period exceeds the exercise price of the option.

In March 2011, 89,865 stock options were granted under the 2010 Equity Incentive Plan to certain executive officers and other officers of the Company with exercise prices equal to the closing market price of the Company's Class A Common Stock on the grant date. These stock options generally vest ratably over a four-year service period from the grant date and are exercisable immediately upon vesting through the tenth anniversary of the grant date.

The fair value of each option granted was estimated using the Black-Scholes option pricing model. Expected volatility was calculated based on the historical volatility of the Company's common stock, and the risk-free interest rate was based on U.S. Treasury yield curve rates with maturities consistent with the expected life of each option. The key assumptions used in computing the weighted average fair market value of stock options granted were as follows:

	2011
Expected volatility	45.00%
Risk-free interest rate	2.54%
Dividend yield	0.62%
Expected term (in years)	6.0

As of September 30, 2011, there was $1.4 million of total unrecognized compensation cost related to outstanding stock options. This cost is expected to be recognized over 3.5 years.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

7. Equity Incentive Compensation Plans (Continued)

Restricted Stock Units

The following table summarizes restricted stock unit (RSU) activity for the nine months ended September 30, 2011:

	RSUs	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at January 1, 2011	857,360	$ 19.67	
Granted	158,333	47.98	
Issued	(18,694)	39.41	$ 877
Canceled/expired	(31,193)	22.86	
Outstanding at September 30, 2011(1)(2)	965,806	$ 23.81	

(1) The balance outstanding includes 30,544 RSUs granted to the non-employee Directors that are 100% vested at date of grant but are subject to a deferral election before the corresponding shares are issued.

(2) The balance outstanding includes 325,123 RSUs granted to executive officers and other officers that have vested in accordance with the RSU agreement, but are subject to a deferral election before the corresponding shares are issued.

As of September 30, 2011, there was $9.3 million of total unrecognized compensation cost related to RSUs granted. This cost is expected to be recognized over 3.5 years.

Performance Share Program

The following table summarizes performance share award activity for the nine months ended September 30, 2011:

	Performance Share Awards	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at January 1, 2011	103,794	$ 31.20	
Granted	65,620	51.86	
Issued			$
Canceled/expired	(6,565)	44.20	
Outstanding at September 30, 2011	162,849	$ 39.00	

In March 2011, 65,620 RSUs that are subject to internal performance metrics and market based vesting criteria in addition to a three-year service condition (performance shares) were granted to executive officers and other officers. The ultimate vesting of awards is contingent upon meeting the established criteria. No performance shares will vest unless, from January 1, 2011 to December 31, 2013, the Company maintains an interest coverage ratio of at least 2.5 to 1.0. If that threshold is met, the number of performance share awards that ultimately vest is based on two equally weighted performance factors: (i) compounded annual production growth as measured by average annual barrels

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

7. Equity Incentive Compensation Plans (Continued)

of oil equivalent per day (BOE/D) and (ii) total shareholder return as compared to the Company's defined peer group for years 2011-2013.

For the portion of performance share awards subject to internal performance metrics, the grant date fair value was determined by reference to the closing price of a share of Class A Common Stock on the date of grant. The Company recognizes compensation expense when it becomes probable that these conditions will be achieved. However, any such compensation expense recognized is reversed if vesting does not actually occur.

For the portion of performance share awards subject to market based vesting criteria, the grant date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing the market-based restricted shares were as follows:

	2011
Number of simulations	100,000
Expected volatility	44%
Risk-free interest rate	1.15%

Compensation expense for performance share awards subject to market based vesting criteria is not reversed if vesting does not actually occur.

As of September 30, 2011, there was $2.0 million of total unrecognized compensation cost related to performance share awards granted. This cost is expected to be recognized over 2.3 years.

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 9 to the Condensed Financial Statements.

As of September 30, 2011, the Company had commodity derivatives associated with the following volumes:

	2011	2012	2013	2014
Oil Bbl/D:	20,020	21,000	15,000	2,000
Natural Gas MMBtu/D:	15,000	15,000		

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

8. Derivative Instruments (Continued)

The Company entered into the following crude oil three-way collars during the nine months ended September 30, 2011:

Term	Average Barrels Per Day	Floor/Swap/Ceiling Prices
February 2011 December 2013	1,000	$70.00 / $90.00 / $116.50
Full year 2012 and 2013	1,000	$70.00 / $90.00 / $120.00
Full year 2012 and 2013	1,000	$70.00 / $95.00 / $120.10
June 2011 December 2014	1,000	$77.95 / $105.00 / $115.00
Full year 2012, 2013, and 2014	1,000	$80.00 / $107.00 / $119.60
Full year 2012 and 2013	500	$70.00 / $90.00 / $100.00
Full year 2012 and 2013	500	$70.00 / $90.00 / $100.00
Full year 2012 and 2013	1,000	$75.00 / $90.00 / $101.85
Full year 2012(1)	1,000	$70.00 / $85.00 / $92.00
Full year 2012(1)	2,000	$70.00 / $80.00 / $83.00
Full year 2012(1)	1,500	$75.00 / $90.00 / $97.50
Full year 2012(1)	500	$75.00 / $90.00 / $106.90

(1) During the third quarter of 2011, the Company converted several of its two-way oil collars to three-way oil collars. There were no payments made or received as a result of these transactions.

Discontinuance of Cash Flow Hedge Accounting

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 accumulated other comprehensive loss (AOCL). As a result of discontinuing hedge accounting on January 1, 2010, the fair values of the Company's open derivative contracts designated as cash flow hedges as of December 31, 2009, less any ineffectiveness recognized, were frozen in AOCL and are reclassified into earnings as the original hedge transactions settle.

At December 31, 2010, AOCL consisted of $70.7 million ($43.8 million, net of income tax) of unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. At September 30, 2011, AOCL consisted of $24.4 million ($15.2 million net of income tax) of unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. During the three and nine months ended September 30, 2011, $15.5 million ($9.6 million, net of income tax) and $46.2 million ($28.6 million, net of income tax), respectively, of non-cash amortization of AOCL related to de-designated hedges was reclassified from AOCL into earnings. The Company expects to reclassify into earnings from AOCL after-tax net losses of $13.4 million related to de-designated commodity and interest rate derivative contracts during the next 12 months.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

8. Derivative Instruments (Continued)

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

	September 30, 2011			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	$ 41.1	Derivative liabilities	$ 3.4
Long term:				
Commodity	Derivative assets	34.7	Derivative liabilities	
Total derivatives		$ 75.8		$ 3.4

	December 31, 2010			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	$ 2.7	Derivative liabilities	$ 84.9
Long term:				
Commodity	Derivative assets	2.1	Derivative liabilities	33.5
Total derivatives		$ 4.8		$ 118.4

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

8. Derivative Instruments (Continued)

The table below summarizes the location and the amount of derivative instrument (gains) losses before income taxes reported in the Condensed Statements of Operations for the periods indicated (in millions):

Description of (Gain) Loss	Location of (Gain) Loss Recognized in Earnings	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Commodity					
(Gain) loss reclassified from AOCL into earnings (amortization of frozen amounts)	Sales of oil and gas	$ 15.5	$ 5.2	$ 45.0	$ 12.1
(Gain) loss recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized (gain) loss on derivatives, net	(162.1)	24.8	(126.4)	(38.9)
Interest rate					
(Gain) loss reclassified from AOCL into earnings (amortization of frozen amounts)	Interest	$	$ 1.9	$ 1.2	$ 7.0
(Gain) loss recognized in earnings (cash settlements and mark-to-market movements)	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, 2011 was $75.8 million.

As of September 30, 2011, the counterparties to the Company's commodity derivative contracts consist of nine financial institutions. The Company's counterparties or their affiliates are also lenders under the Company's Credit Agreement. As a result, the counterparties to the Company's derivative agreements share in the collateral supporting the Company's Credit Agreement. The Company is not generally required to post additional collateral under derivative agreements.

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

8. Derivative Instruments (Continued)

Certain of the Company's derivative agreements contain cross default provisions that require acceleration of amounts due under such agreement if the Company were to default on its obligations under its material debt agreements. In addition, if the Company were to default on certain of its material debt agreements, including, potentially, its derivative agreements, the Company would be in default under the Credit Agreement. As of September 30, 2011, the Company was in a net liability position with two of the counterparties to the Company's derivative instruments, totaling $3.4 million. As of September 30, 2011, the Company's largest three counterparties accounted for 70% of the value of its total net derivative positions.

9. 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 fair value of all derivative instruments is 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 is 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 independent pricing services publish observable market information from multiple brokers and exchanges. 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. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

9. Fair Value Measurements (Continued)

Liabilities Measured at Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy the Company's net derivative liabilities that were measured at fair value on a recurring basis as of September 30, 2011 and December 31, 2010:

(in millions)	Total	Level 1	Level 2	Level 3
Commodity derivative asset (liability), net				
September 30, 2011	$ 72.3	$	$ 72.3	$
December 31, 2010	$ (113.6)	$	$ (11.8)	$ (101.8)

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).

(in millions)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Fair value liability, beginning of period	$	$ (4.0)	$ (101.8)	$ (26.0)
Transfers out of Level 3(1)			101.8	
Realized and unrealized gain (loss) included in earnings		(25.6)		16.3
Settlements		(11.9)		(31.8)
Fair value liability, end of period	$	$ (41.5)	$	$ (41.5)
Total unrealized gain (loss) included in earnings related to financial assets and liabilities still on the Condensed Balance Sheet at September 30, 2011 and 2010	$	$ (37.5)	$	$ (15.5)

(1) During the first quarter of 2011, the inputs used to value oil collars, natural gas collars and natural gas basis swaps were directly or indirectly observable, and these instruments were transferred to level 2.

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

Fair Market Value of Financial Instruments

The Company uses 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

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

9. Fair Value Measurements (Continued)

variable and could be at similar rates today. The fair values of the 2016 Notes, the 2014 Notes, and 2020 Notes were estimated based on quoted market prices. The fair values of the Company's derivative instruments and other investments are discussed above.

	September 30, 2011		December 31, 2010	
(in millions)	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Line of credit	$ 18	$ 18	$ 5	$ 5
Senior secured revolving credit facility	485	485	170	170
8.25% Senior subordinated notes due 2016	200	204	200	210
10.25% Senior notes due 2014, net of discount on carrying amount of $7,227 and $11,035, respectively	352	402	439	518
6.75% Senior notes due 2020	300	285	300	303
	$ 1,355	$ 1,394	$ 1,114	$ 1,206

10. Dry hole, Abandonment, Impairment and Exploration

For the three and nine months ended September 30, 2011, the Company incurred dry hole, abandonment, impairment and exploration expense of $0.2 million and $0.6 million, respectively. 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 the result of mechanical failure encountered on one well in the Piceance. The well was abandoned in favor of drilling a replacement well from the same pad.

11. Commitments and Contingencies

Uinta Crude Oil Sales Contract

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. Gross oil production from the Company's Uinta properties averaged approximately 3,280 Bbl/D in the first nine months of 2011. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the Company's crude oil sales customer in Utah could impact the marketability of a portion of the Company's Utah crude oil volumes. See Item 1A. Risk Factors of the Company's Annual Report on Form 10-K for the year ended December 31, 2010 filed with the SEC on March 1, 2011.

E. Texas Gathering System

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. The transaction was treated as a financing obligation. Accordingly, the $16.7 million net book value of the property is being depreciated over the remaining useful life of the asset and the cash received of $18.4 million was recorded as a financing obligation. A portion of the payments under the agreements are recorded as gathering

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

11. Commitments and Contingencies (Continued)

expense and a portion as interest expense, with the balance being recorded as a reduction to the financing obligation. There are no minimum payments required under these agreements. For the three months ended September 30, 2011 and 2010, the Company recorded $1.2 million and $1.8 million, respectively. For the nine months ended September 30, 2011 and 2010, the Company recorded $4.3 million and $4.6 million, respectively.

Carry and Earning Agreement

On January 14, 2011, the Company entered into an amendment relating to certain contractual obligations to a third party co-owner of certain Piceance assets in Colorado. The amendment waives the $0.2 million penalty for each well not spud by February 2011. The Company is obligated to pay the first $4.5 million of costs incurred by such third party in connection with the construction, on behalf of both the Company and such third party, of either an extension of an existing access road or a new access road. If by December 31, 2012 (which date may, under certain circumstances, be extended until December 31, 2014), the Company has not expended $9.0 million ($4.5 million of which would otherwise be such third party's responsibility) in road construction costs, then it will be obligated to pay the third party 50% of the difference between $12.0 million and the actual amount expended on road construction as of such date. In addition, the amendment extends the date by which the Company must complete its drilling obligations on the North Parachute property to January 31, 2020.

Legal Matters

COGCC Order On April 21, 2011, the Company received a proposed Order Finding Violation from the Colorado Oil and Gas Conservation Commission ("COGCC") alleging that certain releases in late 2007 from a lined reserve pit located on a well pad in western Colorado violated COGCC regulations. Shortly thereafter, the Company entered into negotiations with the COGCC. While the Company denies that it violated any COGCC regulations in connection with the releases, on June 27, 2011, the COGCC approved and the Company later signed an Administrative Order on Consent under which the Company will pay $100,000, and fund a mutually acceptable public project in the amount of $73,000, in full satisfaction of the matter. The Company recorded these amounts in the second quarter of 2011.

BLM Settlement On March 28, 2011, the Company entered into a settlement agreement with the Bureau of Land Management (BLM) resolving all claims by the BLM that the Company did not comply with BLM regulations relating to the operation and position of certain valves, and the submission of related site facility diagrams, in its Uinta operations. The settlement agreement confirmed that the Company promptly remediated the alleged noncompliance upon learning of it, and cooperated with the BLM's investigation, and that there is no evidence of any senior Company management knowledge of the alleged noncompliance, or of any environmental harm or loss of oil or royalty revenue resulting from such alleged noncompliance. The Company paid a $2.1 million civil penalty to the BLM under the settlement agreement in April 2011.

Royalty Payments 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

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

11. Commitments and Contingencies (Continued)

agreements. However, the disputed amounts that the Company may be required to pay are up to approximately $7 million.

Other 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 operating cash flows.

Environmental Matters

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, due to 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 material costs incurred.

12. Subsequent Events

Credit Agreement Amendment

On October 26, 2011, as part of the semi-annual borrowing base redetermination process, the Company entered into a third amendment of its Credit Agreement (the Third Amendment). The borrowing base remained unchanged at $1.4 billion. The Third Amendment increased lender commitments to $1.2 billion. Total fees paid for the October commitment increase were approximately $1.1 million and will be amortized over the remaining term of the Credit Agreement. The Company will write off debt issuance costs of $0.6 million associated with one lender that did not renew its commitment to the Credit Agreement.

10.25% Bond Repurchases

In October 2011, the Company repurchased $3.7 million aggregate principal amount of its 10.25% Notes for an aggregate purchase price of $4.3 million, including accrued and unpaid interest. The related loss of $0.6 million will be recorded in October 2011 and consists of $0.5 million in premium paid over par and $0.1 million in write-offs of net discount and debt issuance costs. These notes were repurchased using available borrowings under the Credit Agreement. The Company may from time to time seek to repurchase its outstanding debt, including additional 10.25% Notes, through open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions and other factors. The amounts repurchased may be material.

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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, 2010, included in our Annual Report on Form 10-K and the Condensed Financial Statements included elsewhere herein.

The profitability of our operations in any particular accounting period is directly related to the realized prices of oil, natural gas and electricity sold, the type and volume of oil and natural 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 natural gas produced may fluctuate based on the success of development and exploitation of oil and natural gas reserves pursuant to current reservoir management. 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. We benefit from lower natural gas prices as we are a consumer of natural gas in our California operations. In the Permian, Uinta, E. Texas, and Piceance, we benefit from higher natural gas pricing as a producer of natural gas. 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.

Diatomite

Although we received a revised project approval letter from the California Department of Conservation, Division of Oil, Gas & Geothermal Resources (DOGGR) for full field development of our Diatomite asset in the third quarter of 2011, more stringent operating requirements recently imposed by state regulatory agencies have negatively impacted the pace of drilling and steam injection and will impact our development of the asset in the near term. As such, we expect that Diatomite production will not meet our previous expectations of 5,000 BOE/D. Our estimates of well performance and recovery for the asset remained unchanged.

Notable Third Quarter 2011 Items

- Generated discretionary cash flow of $123 million from production of 36,900 BOE/D, of which 71% is oil(1)
- Generated operating margin of $46.67 per BOE, supported by sales of our California heavy oil at a $12 average premium to WTI during the quarter(1)
- Increased our average production by 11% from the first nine months of 2010 and 4% from the second quarter of 2011
- Increased our oil production by 14% from the first nine months of 2010 and 6% from the second quarter of 2011
- Permian production averaged 5,200 BOE/D, up 35% from the second quarter of 2011
- Received revised project approval letter from the DOGGR for the full-field development of our Diatomite asset
- Diatomite production averaged 3,820 BOE/D during the third quarter of 2011, up 8% from the second quarter of 2011
- Acquired approximately 11,000 additional net acres in the Permian for $10 million, bringing our total Permian position to 38,000 net acres
- Repurchased $91.0 million aggregate principal amount of our 10.25% Notes
- Drilled three Uteland Butte horizontal wells in Lake Canyon

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Notable Items and Expectations for the Fourth Quarter and Full Year 2011

- Expect to drill four additional Uteland Butte horizontal wells in the fourth quarter
- Expect to drill nine additional Wasatch vertical wells, including two delineation wells
- Repurchased $4 million aggregate principal amount of our 10.25% Notes
- Completed our semi-annual Credit Agreement redetermination and increased lender commitments to $1.2 billion
- Expect to drill 18 Permian wells during the remainder of 2011
- Plan to drill 88 North Midway-Sunset Diatomite wells during the remainder of 2011
- Expect full-year 2011 development capital to be over $500 million, and production in the range of 36,000 BOE/D

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(1) Discretionary cash flow and operating margin are considered non-GAAP performance measures and reference should be made to "Reconciliation of Non-GAAP Measures" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations for further explanation as well as reconciliations to the most directly comparable GAAP measures.

Results of operations.

In the third quarter of 2011, we reported net earnings of $134 million, or $2.42 per diluted share, and net cash flows from operations of $165 million. Net earnings includes a $9.0 million loss associated with repurchasing $91.0 million aggregate principal amount of our 10.25% Notes, a gain on derivatives of $109 million resulting from non-cash changes in fair values and a loss on derivatives of $9.6 million resulting from amortization of accumulated other comprehensive loss (AOCL) related to de-designated hedges.

During the first nine months of 2011, we reported net earnings of $187 million, or $3.38 per diluted share, and net cash flows from operations of $372 million. Net earnings includes a loss of $9.0 million associated with repurchasing $91.0 million principal amount of our 10.25% Notes, a gain on derivatives of $116 million resulting from non-cash changes in fair values and a loss on derivatives of $28.8 million resulting from amortization of AOCL related to de-designated hedges.

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Operating data.

The following table sets forth selected operating data for the three months ended:

	September 30, 2011	%	September 30, 2010	%	June 30, 2011	%
Heavy oil production (BOE/D)	18,173	49	16,722	49	17,670	50
Light oil production (BOE/D)	7,918	22	5,049	15	6,959	19
Total oil production (BOE/D)	26,091	71	21,771	64	24,629	69
Natural gas production (Mcf/D)	64,950	29	72,576	36	65,859	31
Total (BOE/D)(5)	36,916	100	33,867	100	35,606	100
Oil and gas, per BOE:						
Average realized sales price	$ 66.74		$ 48.73		$ 71.07	
Average sales price including cash derivative settlements	67.62		51.88		66.90	
Oil, per Bbl:						
Average WTI price	$ 89.48		$ 76.20		$ 102.34	
Price sensitive royalties(1)	(3.37)		(2.91)		(3.85)	
Quality differential and other(2)	4.45		(8.87)		(0.83)	
Crude oil derivatives non-cash amortization(3)	(6.56)		(2.89)		(6.72)	
Oil revenue	$ 84.00		$ 61.53		$ 90.94	
Add: Crude oil derivatives non-cash amortization(3)	6.56		2.89		6.72	
Crude oil derivative cash settlements(4)	(6.32)		1.14		(13.71)	
Average realized oil price	$ 84.24		$ 65.56		$ 83.95	
Natural gas price:						
Average Henry Hub price per MMBtu	$ 4.20		$ 4.38		$ 4.32	
Conversion to Mcf	0.21		0.22		0.21	
Natural gas derivatives non-cash amortization(3)	0.02		0.09		0.03	
Location, quality differentials and other	(0.18)		(0.40)		(0.17)	
Natural gas revenue per Mcf	$ 4.25		$ 4.29		$ 4.39	
Add: Natural gas derivatives non-cash amortization(3)	(0.02)		(0.09)		(0.03)	
Natural gas derivative cash settlements(4)	0.42		0.35		0.39	
Average realized natural gas price per Mcf	$ 4.65		$ 4.55		$ 4.75	

(1) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of heavy oil posted price above the 2011 base price of $17.09 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in the third quarter of 2011 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $17.43 in 2012.

(2) In California, the oil posting differential at September 30, 2011 was $22.54 and ranged from a low of $5.61 to a high of $22.77 per barrel during the third quarter of 2011. In Utah, the oil posting differential at September 30, 2011 was ($13.00) and averaged ($13.81) during the third quarter of 2011.

(3) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010, and is recorded in Sales of oil and gas.

(4) Cash settlements on derivatives recorded in Realized and unrealized (gain) loss on derivatives, net.

(5) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.

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The following table sets forth selected operating data for the nine months ended:

		September 30, 2011	%		September 30, 2010	%
Heavy oil production (BOE/D)		17,363	49		17,318	54
Light oil production (BOE/D)		7,106	20		4,069	13
Total oil production (BOE/D)		24,469	69		21,387	67
Natural gas production (Mcf/D)		67,097	31		64,002	33
Total (BOE/D)(5)		35,652	100		32,054	100
Oil and gas, per BOE:						
Average realized sales price	$	66.11		$	51.63	
Average sales price including cash derivative settlements		64.63			53.87	
Oil, per Bbl:						
Average WTI price	$	95.42		$	77.70	
Price sensitive royalties(1)		(3.59)			(2.95)	
Quality differential and other(2)		(0.48)			(8.94)	
Crude oil derivatives non-cash amortization(3)		(6.77)			(2.36)	
Oil revenue	$	84.58		$	63.45	
Add: Crude oil derivatives non-cash amortization(3)		6.77			2.36	
Crude oil derivative cash settlements(4)		(10.01)			0.33	
Average realized oil price	$	81.34		$	66.14	
Natural gas price:						
Average Henry Hub price per MMBtu	$	4.21		$	4.60	
Conversion to Mcf		0.21			0.23	
Natural gas derivatives non-cash amortization(3)		0.01			0.10	
Location, quality differentials and other		(0.15)			(0.26)	
Natural gas revenue per Mcf	$	4.28		$	4.67	
Add: Natural gas derivatives non-cash amortization(3)		(0.01)			(0.10)	
Natural gas derivative cash settlements(4)		0.41			0.32	
Average realized natural gas price per Mcf	$	4.68		$	4.89	

(1) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of heavy oil posted price above the 2011 base price of $17.09 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in the first nine months of 2011 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $17.43 in 2012.

(2) In California, the oil posting differential at September 30, 2011 was $22.54 and ranged from a low of ($6.43) to a high of $22.77 per barrel during the first nine months of 2011. In Utah, the oil posting differential at September 30, 2011 was ($13.00) and averaged ($14.43) during the first nine months of 2011.

(3) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010, and is recorded in Sales of oil and gas.

(4) Cash settlements on derivatives recorded in Realized and unrealized (gain) loss on derivatives, net.

(5) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.

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The following table sets forth results of operations (in millions except per share data) for the three month periods ended:

	September 30, 2011	September 30, 2010	3Q10 to 3Q11 Change	June 30, 2011	2Q11 to 3Q11 Change
Sales of oil	$ 200	$ 123	63%	$ 205	(2)%
Sales of gas	25	29	(14)%	26	(4)%
Total sales of oil and gas	$ 225	$ 152	48%	$ 231	(3)%
Sales of electricity	10	9	11%	8	25%
Gas marketing	4	5	(20)%	4	
Interest and other income, net				1	(100)%
Total revenues and other income	$ 239	$ 166	44%	$ 244	(2)%
Net earnings (loss)	$ 134	$ (3)		$ 105	28%
Diluted earnings (loss) per share	$ 2.42	$ (0.06)		$ 1.90	27%

The following table sets forth selected results of operations (in millions except per share data) for the nine month periods ended:

	September 30, 2011	September 30, 2010	% Change
Sales of oil	$ 565	$ 369	53%
Sales of gas	78	82	(5)%
Total sales of oil and gas	$ 643	$ 451	43%
Sales of electricity	24	27	(11)%
Gas marketing	11	18	(39)%
Settlement on Flying J bankruptcy claim		22	(100)%
Interest and other income, net	2	2	
Total revenues and other income	$ 680	$ 520	31%
Net earnings	$ 187	$ 104	80%
Diluted earnings per share	$ 3.38	$ 1.93	75%

Sales of oil and gas.

Sales of oil and gas increased $73 million, or 48%, to $225 million in the third quarter of 2011 compared to $152 million in the third quarter of 2010. The increase is due to an 8% increase in sales volumes and a 37% increase in the average realized sales price in the third quarter of 2011 compared to the third quarter of 2010. Sales of oil and gas decreased $6 million, or 3%, to $225 million in the third quarter of 2011 compared to $231 million in the second quarter of 2011. The decrease is due to a 6% decrease in the average realized sales price, partially offset by a 4% increase in sales volumes in the third quarter of 2011 compared the second quarter of 2011. Sales of oil and gas for the third quarter of 2011 were decreased by non-cash amortization of AOCL related to de-designated hedges of $4.59 per BOE compared to a decrease of $1.66 per BOE in the third quarter of 2010 and $4.61 per BOE in the second quarter of 2011.

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Sales of oil and gas increased $192 million, or 43%, to $643 million for the nine months ended September 30, 2011 compared to $451 million in the nine months ended September 30, 2010. The increase is due to an 11% increase in sales volumes along with a 28% increase in the average realized sales price in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. Sales of oil and gas for the nine months ended September 30, 2011 were decreased by non-cash amortization of AOCL related to de-designated hedges of $4.62 per BOE compared to a decrease of $1.38 per BOE in the nine months ended September 30, 2010.

Approximately 71% of our oil and gas sales volumes in the third quarter of 2011 were oil, with 70% of the oil being heavy oil produced in California, which was sold under various contracts with prices tied to the San Joaquin posted price.

Sales of electricity.

The following table sets forth selected results of operations (in millions except per share data) for the periods ended:

	Three Months Ended			Nine Months Ended	
	September 30, 2011	September 30, 2010	June 30, 2011	September 30, 2011	September 30, 2010
Electricity					
Sales of electricity (in millions)	$ 10	$ 9	$ 8	$ 24	$ 27
Operating costs (in millions)	$ 7	$ 7	$ 7	$ 20	$ 25
Electric power produced MWh/D	2,114	2,091	1,969	1,980	2,084
Electric power sold MWh/D	1,949	1,933	1,810	1,817	1,917
Average sales price/MWh	$ 55.47	$ 53.15	$ 48.34	$ 49.07	$ 53.17
Fuel gas cost/MMBtu (including transportation)	$ 4.38	$ 4.16	$ 4.53	$ 4.42	$ 4.66

Sales of electricity in the third quarter of 2011 increased compared to the third quarter of 2010 due to a 1% increase in electric power sold and a 4% increase in the average sales price. Electricity operating costs in the third quarter of 2011 were consistent with electricity operating costs in the third quarter of 2010. Sales of electricity increased in the third quarter of 2011 compared to the second quarter of 2011 due to a 15% increase in the average sales price of electricity and an 8% increase in electric power sold. Electricity operating costs in the third quarter of 2011 were consistent with electricity operating costs in the second quarter of 2011. We purchased approximately 27,000, 27,000 and 25,000 MMBtu/D of natural gas as fuel for use in our cogeneration facilities for the three months ended September 30, 2011, September 30, 2010 and June 30, 2011, respectively.

Sales of electricity decreased in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 due to an 8% decrease in the average sales price and a 5% decrease in electric power sold due to the shutdown of one of our three cogeneration facilities during March 2011 for scheduled maintenance. Electricity operating costs decreased in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 due to a 5% decrease in electric power produced and a 5% decrease in fuel gas cost.

Recent regulatory developments We operate three cogeneration (also called combined heat and power, or CHP) plants in California to generate lower cost steam compared to conventional steam generation methods. These plants are Qualifying Facilities (QFs) under applicable regulations of the Federal Energy Regulatory Commission (FERC), and as such, the Public Utilities Regulatory Policy Act of 1978 (PURPA) has required California utilities to purchase all electricity produced by our facilities under standard offer (SO) power purchase agreements (PPAs) at the utility's short-run avoided energy

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cost (SRAC) and a capacity price, which reflected an avoidance of capital expenditures that would otherwise have been made by the utility to construct or procure equivalent capacity.

The determination of SRAC, as well as the availability and terms of future PPAs have been highly contentious issues since PURPA was first implemented, resulting in numerous regulatory and legal challenges of California Public Utility Commission (CPUC) decisions dealing with QF issues. Ongoing deregulation of wholesale electricity markets has also resulted in growing pressure by the utilities and regulatory agencies to move QFs away from administratively determined SRAC prices and SO contracts and into the competitive market environment. In an effort to address and resolve these and other issues affecting QFs in California, the CPUC, together with the California investor-owned utilities (IOUs), consumer groups and organizations representing the interests of most CHP QFs in the State, including us, entered into settlement discussions that culminated in a global CHP settlement (the Global Settlement) that was adopted by the CPUC in December 2010. Among the many provisions of the Global Settlement is an agreement by the CHP QFs to support an application at FERC by the three California IOUs to be relieved of their obligation to enter into new contracts pursuant to PURPA to purchase energy and capacity from a QF larger than 20 MW. The FERC has issued a decision granting the IOUs' application that will become effective upon notification by the IOUs to the FERC that the CPUC decision is final and non-appealable. A final and non-appealable FERC decision and a final and non-appealable CPUC decision affirming the Global Settlement are conditions to the effectiveness of the Global Settlement. The CPUC issued a decision on October 6, 2011, the appeal period of which ends on or about November 23, 2011.

The Global Settlement would resolve virtually all of the contested pricing issues between the IOUs and QFs, including most importantly, the claims of retroactive payment adjustments by the IOUs against us and other QFs, all of which will be extinguished. The Global Settlement provides for a gradual and orderly transition over the next four years, and will ultimately require CHP facilities with a rated capacity of more than 20 MW to competitively bid for PPAs with the IOUs. Once effective, the Global Settlement will immediately make available several pro forma PPAs to replace existing PPAs that are SO contracts.

Impact on our electricity contracts We currently sell energy and capacity to Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (Edison) under interim extensions to our legacy PPAs with those utilities. Our current PPAs with Edison for our Placerita Units 1 and 2 are scheduled to terminate within 120 days of the Global Settlement effective date, at which time we intend to enter into one of the new pro forma PPAs with Edison (Transition Contract) for the combined output of the two units. The Transition Contract is similar to our current SO contracts, but with updated regulatory requirements and more stringent scheduling and performance requirements. The Transition Contract will terminate no later than June 30, 2015, but may be terminated earlier if we elect to bid into a competitive CHP solicitation and are awarded a contract based on our bid, the maximum term of which will be seven years.

Our current PPAs with PG&E for our Cogen 18 facility and our Cogen 38 facility are scheduled to expire on December 31, 2011. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it will continue to be eligible for a PURPA contract under which it will be paid the prevailing CPUC-determined SRAC price and either a firm or as-available capacity payment at our discretion. In addition, we will have the option to competitively bid the energy and capacity from our Cogen 18 facility into various competitive solicitations that will be open only to CHP facilities. Upon the scheduled termination of the PPA for Cogen 18 at the end of 2011, we anticipate that we will enter into a new contract with PG&E pursuant to PURPA with a term of up to seven years. Upon the scheduled termination of the PPA for our Cogen 38 facility on December 31, 2011, we anticipate that we will enter into a Transition Contract with PG&E that will terminate no later than June 30, 2015. We also intend to bid into one or more of the CHP only solicitations that are expected to be available as early as the first quarter of 2012.

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The Global Settlement will change the calculation of SRAC for each of our current PPAs, for the Transition Contracts that we intend to execute for the Placerita Facilities and Cogen 38 and for the new PURPA contract that we intend to execute for Cogen 18. The revised SRAC pricing is expected to become effective during the second month following the month in which the Global Settlement becomes effective. The SRAC pricing will be slightly lower than the current SRAC pricing for 2012 through 2014. Beginning in 2015, the energy price will be determined on the basis of electric market prices applicable to the area in which the facility is located. In addition, if California adopts a cap and trade program to reduce greenhouse gas emissions as expected, there may be an additional price adjustment associated with energy sold to an IOU. We do not expect the revised SRAC pricing to be material to us.

Although the Global Settlement provides several inducements to IOUs to enter into future contracts with CHP facilities such as ours, including requirements that IOUs enter into new PPAs (a) for a specified number of MW, (b) that achieve reductions in GHG emissions compared to benchmarks (and our facilities compare favorably to the benchmarks), and (c) for a specified amount of capacity for reliability purposes, and although we will be able to sell energy from our CHP facilities to buyers other than California IOUs, including any wholesale purchaser of electricity in California such as municipal utilities, community choice aggregators and other load serving entities, beginning in July 2015 we will no longer have assurance that that IOUs will continue to purchase electricity from our Placerita or Cogen 38 facilities.

Natural gas marketing.

We have long-term firm transportation contracts on the Rockies Express pipeline from Meeker, CO to Clarington, OH, with total capacity of 35,000 MMBtu/D. We pay a demand charge for this capacity; however, at the present time our own production is insufficient to fully utilize this capacity. In order to maximize the value of this transportation, we purchase our co-working interest owners' share of the gas produced at the market rate for the producing area and entered into FERC-approved Asset Management Agreements with our marketers whereby they fill any remaining unused capacity.

Additionally, we have long-term firm transportation contracts on the Wyoming Interstate Company Pipeline (WIC) from Meeker, CO to Opal, WY and on the Ruby Pipeline from Opal, WY to Malin, OR. These contracts, which became effective July 28, 2011, both have an average total capacity of 35,000 MMBtu/D over a ten-year period. We pay a demand charge for this capacity; however, at the present time, our own production is insufficient to fully utilize this capacity. In order to maximize the value of this transportation, we entered into FERC-approved Asset Management Agreements with a marketer whereby the marketer optimizes our unfilled capacity.

Demand charges paid under the Rockies Express, WIC and Ruby firm transportation contracts are partially offset by payments received under the related Asset Management Agreements.

The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Operations for the three months ended September 30, 2011 and 2010 is $0.3 million and $0.9 million, respectively. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Operations for the nine months ended September 30, 2011 and 2010 is $0.8 million and $2.0 million, respectively.

Firm transportation costs are reflected in Operating costs oil and gas production and total $6.2 million and $4.3 million for the three months ended September 30, 2011 and 2010, respectively, and $14.3 million and $12.1 million for the nine months ended September 30, 2011 and 2010, respectively.

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Oil and gas operating and other expenses.

The following table sets forth our operating expenses for the three months ended:

	Amount Per BOE			Amount (in thousands)		
	September 30, 2011	September 30, 2010	June 30, 2011	September 30, 2011	September 30, 2010	June 30, 2011
Operating costs oil and gas production	$ 18.25	$ 15.01	$ 18.14	$ 61,979	$ 46,782	$ 58,780
Production taxes	2.70	2.00	2.58	9,185	6,215	8,350
DD&A oil and gas production	16.07	15.84	16.04	54,581	49,367	51,967
General and administrative	4.39	3.98	4.91	14,922	12,399	15,910
Interest expense	5.87	5.00	5.47	19,928	15,586	17,712
Total	$ 47.28	$ 41.83	$ 47.14	$ 160,595	$ 130,349	$ 152,719

Operating costs in the third quarter of 2011 were $62.0 million, or $18.25 per BOE, compared to $46.8 million, or $15.01 per BOE, in the third quarter of 2010 and $58.8 million, or $18.14 per BOE, in the second quarter of 2011. The increase in operating costs per BOE in the third quarter of 2011 compared to the third quarter of 2010 is primarily due to increased steam costs. Contract services and transportation costs also increased over the same period. The increase in operating costs per BOE in the third quarter of 2011 compared to the second quarter of 2011 is primarily due to increased transportation costs. 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 sets forth information relating to steam injections for the three months ended:

	September 30, 2011 (3Q11)	September 30, 2010 (3Q10)	3Q10 to 3Q11 Change	June 30, 2011 (2Q11)	2Q11 to 3Q11 Change
Average volume of steam injected (Bbl/D)	137,762	112,379	23%	141,334	(3)%
Fuel gas cost/MMBtu (including transportation)	$ 4.38	$ 4.16	5%	$ 4.53	(3)%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	45,488	34,561	32%	46,940	(3)%

Production taxes in the third quarter of 2011 were $9.2 million, or $2.70 per BOE, compared to $6.2 million, or $2.00 per BOE, in the third quarter of 2010 and $8.4 million, or $2.58 per BOE, in the second quarter of 2011. 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. Our production taxes may vary depending on production from each area, the assessed values of our reserves and the production tax rate in effect. The increase in production taxes per BOE in the third quarter of 2011 compared to the third quarter of 2010 was due to increases in oil prices, an increase in production from our Permian properties and an increase in the assessed ad valorem values attributable to our California properties. The increase in production taxes in the third quarter of 2011 per BOE compared to the second quarter of 2011 was primarily due to an increase in the assessed ad valorem values attributable to our California properties.

Depreciation, depletion and amortization (DD&A) related to oil and gas production in the third quarter of 2011 was $54.6 million, or $16.07 per BOE, compared to $49.4 million, or $15.84 per

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BOE, in the third quarter of 2010 and $52.0 million, or $16.04 per BOE, in the second quarter of 2011. The increase in DD&A per BOE in the third quarter of 2011 compared to the third quarter of 2010 and in the third quarter of 2011 compared to the second quarter of 2011 was primarily due to the development of our properties with higher drilling and leasehold acquisition costs than our California properties, including our recent acquisitions in the Permian, and a shift in production volumes to assets outside of California.

General and administrative expense (G&A) in the third quarter of 2011 was $14.9 million, or $4.39 per BOE, compared to $12.4 million, or $3.98 per BOE, in the third quarter of 2010 and $15.9 million, or $4.91 per BOE, in the second quarter of 2011. The increase in G&A expense per BOE in the third quarter of 2011 compared to the third quarter of 2010 is primarily due to general increases in salaries and benefits, including bonus costs resulting from personnel hired during the past twelve months. In addition, consulting costs increased in the third quarter of 2011 compared to the third quarter of 2010. The decrease in G&A expenses per BOE in the third quarter of 2011 compared to the second quarter of 2011 was primarily due to a decrease in legal fees.

Interest expense in the third quarter of 2011 was $19.9 million, or $5.87 per BOE, compared to $15.6 million, or $5.00 per BOE, in the third quarter of 2010 and $17.7 million, or $5.47 per BOE, in the second quarter of 2011. The increase in interest expense in the third quarter of 2011 compared to the third quarter of 2010 was due to an increase in the amount outstanding under the Credit Agreement, the issuance of $300 million in aggregate principal amount of our 2020 Notes in November 2010 and a decrease in capitalized interest, offset by a decrease of $0.62 per BOE in the non-cash amortization of AOCL losses related to de-designated hedges. The increase in interest expense in the third quarter of 2011 compared to the second quarter of 2011 was primarily due to a decrease in capitalized interest.

The following table sets forth our operating expenses for the nine months ended:

	Amount Per BOE		**Amount (in thousands)**	
	September 30, 2011	**September 30, 2010**	**September 30, 2011**	**September 30, 2010**
Operating costs oil and gas production	$ 18.27	$ 16.03	$ 177,842	$ 140,269
Production taxes	2.56	1.88	24,926	16,484
DD&A oil and gas production	16.30	14.74	158,657	128,976
General and administrative	4.84	4.39	47,123	38,389
Interest expense	5.48	5.64	53,295	49,373
Total	$ 47.45	$ 42.68	$ 461,843	$ 373,491

Operating costs in the nine months ended September 30, 2011 were $178 million or $18.27 per BOE, compared to $140 million or $16.03 per BOE in the nine months ended September 30, 2010. The increase in operating costs per BOE in the first nine months of 2011 compared to the first nine months of 2010 is primarily due to increased steam costs. Contract services and well servicing costs also increased over the same period. 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.

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The following table sets forth information relating to steam injections for the nine months ended:

	September 30, 2011	September 30, 2010	Change
Average volume of steam injected (Bbl/D)	132,781	113,836	17%
Fuel gas cost/MMBtu (including transportation)	$ 4.42	$ 4.66	(5)%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	44,355	34,877	27%

Production taxes in the nine months ended September 30, 2011 were $24.9 million, or $2.56 per BOE, compared to $16.5 million, or $1.88 per BOE, in the nine months ended September 30, 2010. Severance taxes paid in Utah, Colorado and Texas are directly related to the field sales price. In California, our production is burdened with ad valorem taxes on our total proved reserves. Our production taxes may vary depending on production from each area, the assessed values of our reserves, and the production tax rate in effect. The increase in production taxes for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 was due to increases in oil prices, an increase in production from our Permian properties and an increase in the assessed ad valorem values attributable to our California properties.

DD&A in the nine months ended September 30, 2011 was $159 million, or $16.30 per BOE, compared to $129 million, or $14.74 per BOE, in the nine months ended September 30, 2010. The increase per BOE is primarily due to an increase in production from the Permian and other assets outside of California, which have higher per barrel DD&A rates than our California properties.

G&A in the nine months ended September 30, 2011 was $47.1 million, or $4.84 per BOE, compared to $38.4 million, or $4.39 per BOE in the nine months ended September 30, 2010. The increase is primarily due to general increases in salaries and benefits, including bonus costs resulting from personnel hired during the past twelve months. Additionally, technology consulting, property evaluation, office hardware, office software, and tax consulting costs increased during the same time period.

Interest expense in the nine months ended September 30, 2011 was $53.3 million, or $5.48 per BOE, compared to $49.4 million, or $5.64 per BOE, in the nine months ended September 30, 2010. The increase in interest expense in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, is due to an increase in the amount outstanding under the Credit Agreement and the issuance of $300 million in aggregate principal amount of our 2020 Notes in November 2010, partially offset by a decrease of $0.68 per BOE in the non-cash amortization of AOCL related to de-designated hedges.

Realized and unrealized (gain) loss on derivatives, net.

Realized and unrealized (gain) loss on derivatives, net includes the realized gains and losses (cash settlements) and unrealized gains and losses (non-cash changes in fair value) of our derivative instruments. 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 recorded to earnings under the caption Realized and unrealized (gain) loss on derivatives, net. See Notes 8 and 9 to the Condensed Financial Statements for more information on our derivative instruments.

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The following table sets forth the cash settlements and non-cash derivative contract fair value gains and losses recorded in Realized and unrealized (gain) loss on derivatives, net for the periods indicated:

	Three Months Ended			Nine Months Ended	
(in thousands)	September 30, 2011	September 30, 2010	June 30, 2011	September 30, 2011	September 30, 2010
Cash (receipts) payments:					
Commodity derivatives oil	$ 15,016	$ (2,287)	$ 30,831	$ 66,856	$ (1,894)
Commodity derivatives natural gas	(2,491)	(2,342)	(2,319)	(7,402)	(5,617)
Financial derivatives interest		1,812			5,466
Total cash (receipts) payments	$ 12,525	$ (2,817)	$ 28,512	$ 59,454	$ (2,045)
Mark-to-market (gain) loss:					
Commodity derivatives oil	$ (172,875)	$ 36,502	$ (121,013)	$ (186,799)	$ (15,236)
Commodity derivatives natural gas	(1,795)	(7,121)	693	908	(16,172)
Financial derivatives interest		614			2,971
Total mark-to-market (gain) loss	$ (174,670)	$ 29,995	$ (120,320)	$ (185,891)	$ (28,437)
Total realized and unrealized (gain) loss on derivatives, net	$ (162,145)	$ 27,178	$ (91,808)	$ (126,437)	$ (30,482)

Gain on purchase.

In the nine months ended September 30, 2011, we recorded a $1.0 million gain (net of deferred income taxes of $0.7 million) in conjunction with usual and customary post-closing adjustments to the purchase price of the November 2010 Permian acquisition. The gain was recorded in the Condensed Statements of Operations under the caption Gain on purchase.

Transaction costs on acquisitions.

In the nine months ended September 30, 2010, we incurred $2.6 million in acquisition costs related to our March 2010 acquisition of certain properties in the Permian.

Extinguishment of debt.

In the nine months ended September 30, 2011, we recorded a $14.4 million loss in Extinguishment of debt, consisting of $11.0 million in premium paid over par and $3.4 million in write-offs of net discount and debt issuance costs related to our repurchase of $91.0 million aggregate principal amount of our 10.25% Notes in August and September 2011. These notes were repurchased for an aggregate purchase price of $104.5 million, including accrued and unpaid interest, using available borrowing under the Credit Agreement.

Dry hole, abandonment, impairment and exploration.

For the three and nine months ended September 30, 2011, we incurred dry hole, abandonment, impairment and exploration expense of $0.2 million and $0.6 million, respectively. For 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. The cost recognized in the nine months ended September 30, 2010 was primarily a result of mechanical failure encountered on one well in the Piceance. The well was abandoned in favor of drilling a replacement well from the same pad.

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Income tax expense.

The effective income tax rate for the three months ended September 30, 2011 and 2010 was 37.8% and 20.8%, respectively. The lower effective income tax rate in the three months ended September 30, 2010 is primarily due to a 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 effective income tax rate for the nine months ended September 30, 2011 and 2010 was 37.6% and 38.3%, respectively. Our estimated annual effective income tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences (*i.e.*, differences between book earnings and tax earnings that are not expected to reverse in future periods). See Note 4 to the Condensed Financial Statements.

Drilling activity.

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

Asset Team	Three Months Ended September 30, 2011 Gross Production Wells	Three Months Ended September 30, 2011 Net Production Wells	Nine Months Ended September 30, 2011 Gross Production Wells	Nine Months Ended September 30, 2011 Net Production Wells
SMWSS Steam Floods	6	6	40	40
NMWSS Diatomite	34	34	139	139
Permian	26(1)	20	75(2)	55
Uinta	12	8	39	33
E. Texas				
Piceance			5	5
Totals	78	68	298	272

(1) Includes six wells in which we have an average interest of approximately 0.70% each, or approximately 0.04 total net wells.

(2) Includes 17 wells in which we have an average interest of approximately 0.70% each, or approximately 0.11 total net wells.

Properties.

We currently have six asset teams as follows: South Midway-Sunset (SMWSS) Steam Floods, North Midway-Sunset (NMWSS) Diatomite, Permian, Uinta, E. Texas and Piceance.

SMWSS Steam Floods Our SMWSS Steam Floods asset team includes our Homebase, Formax, Ethel D, Placerita and Poso Creek properties. In the third quarter of 2011, we drilled 6 gross (6 net) productive wells, including two vertical producers at Ethel D and four vertical producers at our Placerita property. These new wells are currently on production. Average daily production in the third quarter of 2011 from all of our SMWSS Steam Floods assets was approximately 13,230 BOE/D, an increase of 80 BOE/D from the second quarter of 2011.

NMWSS Diatomite Our NMWSS Diatomite asset team comprises several properties in the North Midway-Sunset area including our Diatomite and McKittrick assets. Average daily production from all of our NMWSS Diatomite assets in the third quarter of 2011 was approximately 4,940 BOE/D, a 9% increase from the second quarter of 2011. Diatomite production in the third quarter of 2011 averaged 3,820 BOE/D, an increase of 8% from the second quarter of 2011. During the third quarter of 2011, we drilled 22 gross (22 net) wells at our McKittrick property and 12 gross (12 net) wells at our other

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non-Diatomite NMWSS properties. Although we received a revised project approval letter from the DOGGR for full field development of our Diatomite asset in the third quarter of 2011, more stringent operating requirements recently imposed by state regulatory agencies have negatively impacted the pace of drilling and steam injection and will impact our development of the asset in the near term. We are utilizing cyclic steam injection to produce this unique reservoir, which is requiring close monitoring of steam volumes to minimize steam to surface as well as wellbore failures. Our estimates of well performance and recovery for the asset remained unchanged. Fourth quarter drilling will include approximately 88 wells at our NMWSS properties with approximately 35 of those in the Diatomite.

Permian During the third quarter of 2011, our Permian drilling program averaged 5 rigs and we drilled 20 gross (20 net) wells. Our drilling inventory in the Permian is approximately 450 locations on 40-acre spacing. We drilled and completed a majority of our Permian wells below the Wolfcamp in the deeper zones including the Strawn, Atoka and Mississippian. We plan to drill 18 wells in the fourth quarter, while completing 16 wells by the end of 2011. Average production in the third quarter of 2011 from our Permian assets averaged 5,200 BOE/D, a 35% increase from the second quarter of 2011.

Uinta During the third quarter of 2011, we drilled 12 gross wells (8 net) including five wells in Ashley National Forest and seven wells in Lake Canyon. Of the seven wells in Lake Canyon, four were Green River/Wasatch commingled wells and three were Uteland Butte horizontal wells. We expect to have nine Uteland Butte horizontal wells drilled by the end of 2011, three of which will be operated wells. In addition, we expect to drill one Brundage Canyon Wasatch well, five Ashley Forest Green River wells, six Lake Canyon Green River/Wasatch wells and two Wasatch delineation wells. Our Ashley National Forest Environmental Impact Study continues to progress, with a Record of Decision expected by the end of 2011. Average daily production from our Uinta assets averaged 5,540 BOE/D.

E. Texas In 2010, we completed an eight-well Haynesville horizontal development program at Darco. All of those wells are now online, and production continues to meet our expectations. We have deferred drilling in E. Texas in 2011 while we focus on higher return oil development opportunities at our other properties. Average daily production in the third quarter of 2011 from the E. Texas assets was 23 MMcf/D.

Piceance During the third quarter of 2011, we completed four wells, and production results continue to meet our expectations. We are currently deferring drilling in the Piceance while we focus on higher return oil development opportunities at our other properties. Average daily production in the third quarter of 2011 from the Piceance assets was 25 MMcf/D.

Financial condition, liquidity and capital resources.

Our development, exploitation, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and borrowings under our Credit Agreement 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 the level of cash flows generated from our 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. As of September 30, 2011, we have approximately 70% and 65% of our expected 2011 and 2012 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 flows that we will receive for a portion of our production in 2011 and 2012. In the future, we may increase or decrease our derivative positions. Our derivatives counterparties are commercial banks that are parties to our Credit Agreement, or affiliates of those banks. See Item 3. Quantitative and Qualitative Disclosures About Market Risk below and

Notes 8 and 9 to the Condensed Financial Statements for further details about our derivative instruments.

On April 13, 2011, we amended our Credit Agreement, which extended the maturity date of the Credit Agreement to May 13, 2016 and increased the borrowing base from $875 million to $1.4 billion. Lender commitments remained unchanged at $875 million at the time of the amendment. In addition, the amendment reduced the LIBOR margin to between 1.50% and 2.50%, the prime rate margin to between 0.50% and 1.50% and the annual commitment fee on the unused portion of the Credit Agreement to between 0.35% and 0.50%. The amendment also provides the right for us to refinance our 2014 Notes and 2016 Notes with similar notes or retire the 2014 Notes or the 2016 Notes using available borrowing under the Credit Agreement as long as certain leverage and liquidity tests are met. See Note 3 to the Condensed Financial Statements.

In August 2011, we obtained an additional $100 million of lender commitments under our Credit Agreement, increasing total lender commitments to $975 million. On October 26, 2011, as part of the semi-annual borrowing base redetermination process, we entered into the Third Amendment. The borrowing base remained unchanged at $1.4 billion. The Third Amendment increased lender commitments to $1.2 billion, increasing available borrowing capacity at that date to approximately $680 million. Total fees paid for the August and October commitment increases were approximately $0.5 million and $1.1 million, respectively, and will be amortized over the remaining term of the Credit Agreement. We will write off debt issuance costs of $0.6 million associated with one lender that did not renew its commitment to the Credit Agreement.

The maximum amount available is subject to semi-annual redeterminations of the borrowing base based on the value of our proved oil and natural gas reserves, in April and October of each year in accordance with the lenders' customary procedures and practices. We and the lenders each have the unilateral right to one redetermination each year. The Credit Agreement is collateralized by our oil and natural gas properties. In addition, we may borrow up to $40.0 million for a maximum of 30 days under our Line of Credit. We do not expect the Line of Credit to be available to us for the remainder of 2011. However, this does not impact our total available borrowing capacity. Our total outstanding debt at September 30, 2011 under the Line of Credit and Credit Agreement was $503 million, with an additional $24 million in letters of credit issued under the Credit Agreement, leaving $448 million in borrowing capacity available.

In August and September 2011, we repurchased $91.0 million aggregate principal amount of our 10.25% Notes for an aggregate purchase price of $104.5 million, including accrued and unpaid interest. The related loss of $14.4 million recorded in Extinguishment of debt consists of $11.0 million in premium paid over par and $3.4 million in write-offs of net discount and debt issuance costs. In October 2011, we repurchased $3.7 million aggregate principal amount of our 10.25% Notes for an aggregate purchase price of $4.3 million, including accrued and unpaid interest. The related loss of $0.6 million will be recorded in the fourth quarter of 2011 and consists of $0.5 million in premium paid over par and $0.1 million in write-offs of net discount and debt issuance costs. These notes were retired using available borrowings under our Credit Agreement. We may from time to time seek to repurchase our outstanding debt, including additional 10.25% Notes, through open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts repurchased may be material.

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 Class A Common Stock at a price of $29.25 per share and received $224 million of net proceeds. We used the net proceeds to fund an acquisition in the Permian in March 2010 and to reduce our outstanding borrowings under the Credit Agreement. In November 2010, we issued $300 million in principal amount of our 2020 Notes and received net proceeds of $294 million, which were used in part to finance an acquisition in the Permian in November 2010. The remainder was used to reduce outstanding borrowings under our Credit Agreement. Our ability to access the debt and equity capital markets on economic 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.

At September 30, 2011, we had a working capital deficit of approximately $60.9 million. We generally maintain a working capital deficit because we use excess cash to reduce borrowings under our Credit Agreement. Our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

Credit ratings.

Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate our Senior Notes and have assigned us a credit rating. We do not have any provisions that are linked to our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our currently outstanding debt. However, our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Historical cash flows.

Operating activities Net cash provided by operating activities is primarily affected by the price of oil and natural gas, production volumes and changes in working capital. The increase in net cash provided by operating activities of $53.4 million in the first nine months of 2011 compared to the first nine months of 2010 is primarily due to increased production and an increase in the average realized sales price.

Investing activities Net cash used in investing activities is primarily comprised of acquisition, exploration and development of oil and gas properties net of dispositions of oil and gas properties. The increase in net cash used in investing activities in the first nine months of 2011 compared to the first nine months of 2010 is primarily due to an increase of $193 million in cash used for the exploration and development of our oil and gas properties in the first nine months of 2011 compared to the first nine months of 2010.

Financing activities Net cash provided by financing activities in the first nine months of 2011 included net borrowings under our Credit Agreement and Line of Credit of $327 million. Net cash provided by financing activities in the first nine months of 2010 included proceeds from the issuance of Class A Common Stock of $224 million, offset by the net repayment of borrowings under our Credit Agreement and Line of Credit of $132 million and dividends paid of $12.1 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. To compensate for the slower pace of development in the Diatomite, we are investing additional capital in our other assets. For 2011, we are expecting full-year development capital of over $500 million.

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 for the remainder of 2011. However, if our revenue and cash flow decrease as a result of deterioration in economic conditions or an adverse change in commodity prices, we 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.

Recent accounting standards and updates.

In May 2011, the FASB issued Accounting Standards Update (ASU) No. 2011-04 *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in US GAAP and IFRSs.* The ASU amends previously issued authoritative guidance, is effective for interim and annual periods beginning after December 15, 2011. The amendments change requirements for measuring fair value and disclosing information about those measurements. Additionally, the ASU clarifies the FASB's intent regarding the application of existing fair value measurement requirements and changes certain principles or requirements for measuring fair value or disclosing information about its measurements. For many of the requirements, the FASB does not intend the amendments to change the application of the existing Fair Value Measurements guidance. This guidance will not have an impact on our financial position or results of operations.

In June 2011, the FASB issued ASU No. 2011-05 *Presentation of Comprehensive Income.* The ASU amends previously issued authoritative guidance and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. These amendments remove the option under current U.S. GAAP to present the components of other comprehensive income as part of the statements of changes in stockholder's equity. The adoption of this guidance will not have an impact on our financial position or results of operations, but will require us to present the statements of comprehensive income separately from the statements of equity, as these statements are currently presented on a combined basis.

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 periods presented:

(in millions)	**Three Months Ended September 30, 2011**	**Nine Months Ended September 30, 2011**
Net cash provided by operating activities	$ 165	$ 372
Add back: Net increase in current assets	7	26
Add back: Net decrease (increase) in current liabilities including book overdraft	(49)	(70)
Discretionary cash flow	$ 123	$ 328

Operating margin per BOE In addition to reporting net earnings as defined under GAAP, we present operating margin, which is a non-GAAP profitability measure. Operating margin per BOE consists of oil and gas revenues less oil and gas operating expenses and production taxes divided by the total BOE sold during the period. Management uses operating margin per BOE as a measure of profitability and believes it provides useful information to investors because it relates our oil and gas

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revenue and gas operating expenses to our total units of production, providing a gross margin per unit of production. Using this measure, investors can evaluate how profitability varies on a per unit basis each period.

(Per BOE)	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
Average sales price including cash derivative settlements	$ 67.62	$ 64.63
Average operating costs oil and gas production	18.25	18.27
Average production taxes	2.70	2.56
Average operating margin	$ 46.67	$ 43.80

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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 the 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 are options positions by which the proceeds from the sale of the call option fund the purchase of a put option.

As of September 30, 2011, we have approximately 70% and 65% of our expected 2011 and 2012 oil production, respectively, hedged in the form of swaps and collars. A hypothetical $10 increase in the oil prices used and $1 increase in the natural gas prices used to calculate the fair values of our crude oil derivative instruments at September 30, 2011 would decrease the respective fair value of crude oil and natural gas derivative instruments at September 30, 2011 by $95.3 million and $4.0 million, respectively. A hypothetical $10 decrease in the oil prices used and $1 decrease in the natural gas prices used to calculate the fair values of our crude oil derivative instruments at September 30, 2011 would increase the respective fair value of crude oil and natural gas derivative instruments at September 30, 2011 by $83.8 million and $4.2 million, respectively.

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The following table summarizes our commodity derivative position as of September 30, 2011:

Term	Average Barrels Per Day	Average Prices	Term	Average Barrels/MMBtu Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Three-Way Collars			**Crude Oil Sales (NYMEX WTI) Collars**		
Full year 2011	500	$65.00/$85.00/$97.25	Full year 2011	270	$80.00/$90.00
Full year 2011	1,000	$70.00/$87.00/$105.00	Full year 2011	1,000	$55.20/$70.00
Full year 2011	1,000	$55.00/$75.00/$91.63	Full year 2011	1,000	$55.00/$70.50
Full year 2011	1,000	$60.00/$80.00/$101.00	Full year 2011	1,000	$55.00/$68.65
Full year 2011	1,000	$70.00/$88.15/$100.00	Full year 2011	1,000	$55.00/$68.00
Full year 2011	1,000	$70.00/$86.85/$100.00	Full year 2011	1,000	$55.00/$71.20
Full year 2011	1,000	$69.70/$85.00/$100.00	Full year 2011	1,000	$60.00/$76.00
Full year 2011	500	$70.00/$85.00/$94.68	Full year 2011	1,000	$60.00/$81.25
Feb - Dec 2011	1,000	$70.00/$90.00/$116.50	Full year 2011	500	$75.00/$101.15
Jun - Dec 2011	1,000	$77.95/$105.00/$115.00	Full year 2011	500	$75.00/$100.75
Full year 2012	1,000	$65.00/$85.00/$97.25	Full year 2011	1,000	$75.00/$91.25
Full year 2012	1,000	$70.00/$87.00/$105.00			
Full year 2012	1,000	$70.00/$88.00/$106.00	**Crude Oil Sales (NYMEX WTI) Swaps**		
Full year 2012	1,000	$60.00/$80.00/$96.92	Full year 2011	500	$57.36
Full year 2012	1,000	$60.00/$80.00/$120.00	Full year 2011	500	$57.40
Full year 2012	1,000	$70.00/$88.15/$100.00	Full year 2011	500	$57.50
Full year 2012	1,000	$70.00/$86.85/$100.00	Full year 2011	250	$61.80
Full year 2012	1,000	$69.70/$85.00/$100.00			
Full year 2012	1,000	$70.00/$87.00/$108.50	**Natural Gas Sales (NYMEX HH) Swaps**		
Full year 2012	1,000	$70.00/$90.00/$116.50	Full year 2011	5,000	$6.89
Full year 2012	1,000	$70.00/$90.00/$120.00	Full year 2011	5,000	$5.50
Full year 2012	1,000	$70.00/$95.00/$120.10	Full year 2012	5,000	$7.16
Full Year 2012	1,000	$77.95/$105.00/$115.00	Full year 2012	5,000	$5.75
Full Year 2012	1,000	$80.00/$107.00/$119.60			
Full year 2012	500	$70.00/$90.00/$100.00	**Natural Gas Sales (NYMEX HH) Collars**		
Full year 2012	500	$70.00/$90.00/$100.00	Full year 2011	5,000	$6.00/$7.25
Full year 2012	1,000	$75.00/$90.00/$101.85	Full year 2012	5,000	$6.00/$7.70
Full year 2012(1)	1,000	$70.00/$85.00/$92.00			
Full year 2012(1)	2,000	$70.00/$80.00/$83.00	**Natural Gas Sales (NYMEX HH to NGPL-Tex OK)**		
Full year 2012(1)	1,500	$75.00/$90.00/$97.50	**Basis**		
Full year 2012(1)	500	$75.00/$90.00/$106.90		2,500	$0.46

			Full year 2011		
Full year 2013	1,000	$65.00/$85.00/$97.25	Full year 2012	2,500	$0.44
Full year 2013	1,000	$70.00/$87.00/$105.00			
Full year 2013	1,000	$70.00/$88.00/$106.00	**Natural Gas Sales (NYMEX HH TO HSC)**		
Full year 2013	1,000	$60.00/$80.00/$103.30		**Basis Swaps**	
Full year 2013	1,000	$70.00/$88.15/$100.00	Full year 2011	2,500	$0.33
Full year 2013	1,000	$70.00/$86.85/$100.00	Full year 2012	2,500	$0.32
Full year 2013	1,000	$69.70/$85.00/$100.00			
Full year 2013	1,000	$70.00/$87.00/$108.50			
Full year 2013	1,000	$70.00/$90.00/$116.50			
Full year 2013	1,000	$70.00/$90.00/$120.00			
Full year 2013	1,000	$70.00/$95.00/$120.10			
Full year 2013	1,000	$77.95/$105.00/$115.00			
Full year 2013	1,000	$80.00/$107.00/$119.60			
Full year 2013	500	$70.00/$90.00/$100.00			
Full year 2013	500	$70.00/$90.00/$100.00			
Full year 2013	1,000	$75.00/$90.00/$101.85			
Full year 2014	1,000	$77.95/$105.00/$115.00			
Full year 2014	1,000	$80.00/$107.00/$119.60			

(1) During the third quarter of 2011, we converted several of our two-way oil collars to three-way oil collars. There were no payments made or received as a result of these transactions.

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Excluded from the table above are our calendar month average swaps, which protect us from variances in market pricing conditions of certain of our sales contracts. These derivative contracts protect 5,000 BOE/D of our Permian sales volumes and have differentials of $0.25 from October through December 2011, $0.07 to $0.08 during 2011 and $0.075 to $0.080 during 2012.

Interest rate risk.

Our Credit Agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to 12 months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the Credit Agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt. At September 30, 2011, our outstanding principal balance under our Credit Agreement was $485 million and the weighted average interest rate on the outstanding principal balance was 2.0%. At September 30, 2011, the carrying amount approximated fair market value. Assuming a constant debt level of $1.4 billion, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $3.1 million over a 12-month time period.

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Item 4. Controls and Procedures

As of September 30, 2011, 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 (the Exchange Act).

Our Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2011, our disclosure controls and procedures are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and 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 were no changes in our internal control over financial reporting that occurred during the three months ended September 30, 2011 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

Any statements in this Form 10-Q that are not historical facts, including with respect to expected future production, are forward-looking statements that involve risks and uncertainties. Words such as "plan," "will," "intend," "continue," "target(s)," "expect," "achieve," "future," "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. of our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 1, 2011, under the heading "Risk Factors".

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information set forth under "Legal Matters" in Note 11 of our Notes to Condensed Financial Statements included in Item 1 of Part I of this quarterly report is incorporated by reference in response to this item.

Item 1A. Risk Factors

Recent regulatory changes in California have and may continue to negatively impact our production in our Diatomite assets. Recent regulatory changes in California have impacted our Diatomite production. In 2010, Diatomite production decreased significantly due to the inability to drill new wells pending the receipt of permits from the DOGGR. In July 2011, we received a revised project approval letter from the DOGGR for full field development of our Diatomite asset. The approval, among other things, included more stringent operating, response and preventative requirements relating to mechanical integrity testing and responses to integrity issues and surface expressions, among others. Compliance with these requirements and delays in regulatory reviews, as well as other regulatory action and inaction, negatively impact the pace of drilling and steam injection and will impact our development of the asset in the near term. We may not be successful in streamlining the review process with the DOGGR or in taking additional steps to more efficiently manage our operations to avoid additional delays. In addition, the DOGGR may impose additional operational restrictions or requirements as a result of recent incidents involving surface expressions in the North Midway-Sunset field. Diatomite production averaged 3,820 BOE/D during the third quarter of 2011.

We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. We are dependent on several cogeneration facilities that, combined, provide approximately 27% of our steam capacity as of December 31, 2010. These facilities are dependent on reasonable contracts for the sale of electricity. If, for any reason, including if utilities that purchase electricity from us are no longer required by regulation to enter into electricity sales contracts with us, we were unable to enter into new or replacement contracts or were to lose any existing contract, we may not be able to supply 100% of the steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements and availability of equipment. The financial cost and timing of such new investment may adversely affect our production, capital outlays and cash provided by operating activities.

We currently sell energy and capacity to PG&E and Edison under interim extensions to our legacy PPAs with those utilities. Our current PPAs with Edison for our Placerita Units 1 and 2 are scheduled to terminate within 120 days of the Global Settlement effective date, at which time we intend to enter into a Transition Contract for the combined output of the two units. The Transition Contract is similar to our current SO contracts, but with updated regulatory requirements and more stringent scheduling and performance requirements. The Transition Contract will terminate no later than June 30, 2015, but may be terminated earlier if we elect to bid into a competitive CHP solicitation and are awarded a contract based on our bid, the maximum term of which will be seven years. Our current PPAs with PG&E for our Cogen 18 facility and our Cogen 38 facility are scheduled to expire on December 31, 2011. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it will continue to be eligible for a PURPA contract under which it will be paid the prevailing CPUC-determined SRAC price and either a firm or as-available capacity payment at our discretion. In addition, we will have the option to competitively bid the energy and capacity from our Cogen 18 facility into various competitive solicitations that will be open only to CHP facilities. Upon the scheduled termination of the PPA for Cogen 18 at the end of 2011, we anticipate that we will enter into a new contract with PG&E pursuant to PURPA with a term of up to seven years. Upon the scheduled termination of the PPA for our Cogen 38 facility on December 31, 2011, we anticipate that we will enter into a Transition Contract with PG&E that will terminate no later than June 30, 2015. We also intend to bid into one or more of the CHP only solicitations that are expected to be available as early as the first quarter of 2012.

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. For a discussion of the status of our electricity sales contracts, see "We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly" above. Legal and regulatory decisions (especially related to the pricing of electricity under the contracts such as the SRAC Decision 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 SRAC pricing formula, which became effective on August 1, 2009 retroactively, so as to require payment on a one-time basis, could have a material adverse effect on our financial condition, results of operations, and operating cash flows. During the California energy crisis in 2000 and 2001, we had electricity sales contracts with PG&E and Edison, 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 December 21, 2010, the CPUC issued an order that approves a Global Settlement 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, which upon its effectiveness would extinguish all pending claims of retroactive payment liability, would make available long-term standard form QF contracts and would prospectively revise SRAC pricing. The Global Settlement includes an agreement by the CHP QFs to support an application at FERC by the three California IOUs to be relieved of their obligation to enter into new contracts pursuant to PURPA to purchase energy and capacity from a QF larger than 20 MW. The FERC has issued a decision granting the IOUs' application that will become effective upon notification by the IOUs to the FERC that the CPUC decision is final and non-appealable. A final and non-appealable FERC decision and a final and non-appealable CPUC decision affirming the Global Settlement are conditions to the effectiveness of the Global Settlement. The CPUC issued a decision on October 6, 2011, the appeal period of which ends on or about November 23, 2011.

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 health 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. Following issuance of this finding, the EPA 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. 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

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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. With regard to the monitoring and reporting of GHGs, on December 17, 2010, the EPA amended the "Mandatory Reporting of Greenhouse Gases" rule (Reporting Rule), originally issued in September 2009. The Reporting Rule establishes a comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gases emissions annually on a facility-by-facility basis. Further, on November 8, 2010, EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA's GHG Reporting Rule. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO2 equivalent per year will now be required to report annual GHG emissions to EPA, with the first report due on March 31, 2012.

Similarly, legislation has from time to time been introduced in the United States Congress that would establish measures restricting greenhouse gas emissions in the United States. At the state level, over 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. On October 20, 2011, California became the first state to adopt a cap and trade program to reduce GHG emissions. The new regulations, which will take effect in 2013, will require us to continue to report our GHG emissions and will set maximum limits or caps, in the form of annual GHG allowance budgets, on emissions of GHGs from our facilities and operations. The emissions caps are established based on three years of baseline emissions data, and the cap applicable to our facilities and operations will be set at some percentage of the 2012 emissions level forecast. The cap will decline annually thereafter through 2020. We will be required to either reduce our GHG emissions below the applicable cap or obtain compliance instruments, in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. The availability of allowances may decline over time, and the cost to acquire such allowances may increase over time. We are currently assessing the impact of these regulations on our operations, including the costs to acquire allowances and to reduce emissions. Our early estimates indicate that, based on our understanding of the current market price of allowances, the manner in which cost-free allowances are to be distributed by CARB to the oil and gas extraction industry and our current production and emissions estimates, among other factors, our cost of acquiring allowances beginning in 2013 may be in the range of $2.00-3.00 per barrel. The actual cost to acquire allowances will depend on the market price for such allowances at the time they are purchased, and the level of allowances we are required to purchase will depend on our actual production and emissions. The cap and trade program is currently scheduled to be in effect through 2020 and, given the uncertainties regarding the markets for allowances, how allowances will be distributed among various industry sectors and our ability to limit our GHG emissions and implement cost-containment measures, we are unable to estimate the net cost to us to comply with the cap and trade regulations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Congress has, in the past, considered two companion bills for the "Fracturing Responsibility and Awareness of Chemicals Act" (the FRAC Act). While now dead, if reintroduced, 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. If reintroduced, the 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, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA and has begun the process of drafting guidance documents on regulatory requirements for companies that plan to conduct hydraulic fracturing using diesel. Also, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit and reporting requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. Only recently, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or otherwise.

The adoption of any future federal or state laws or implementing regulations 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 obtain permits and could increase our costs of compliance and doing business.

For additional information about our risk factors, see Item 1A. of our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the SEC on March 1, 2011. For additional information on recent developments in the California utility market, see "Sales of Electricity" in Item 2. Management's Discussion and Analysis of Financial Condition and 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

None.

Item 5. Other Information

None.

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Item 6. Exhibits

Exhibit No.	Description of Exhibit
4.1*	Second Amendment to the Second Amended and Restated Credit Agreement dated June 17, 2011 by and among the Registrant and Wells Fargo Bank, N.A. and other lenders
4.2	Third Amendment to the Second Amended and Restated Credit Agreement dated October 26, 2011 by and among the Registrant and Wells Fargo Bank, N.A. and other lenders (filed as exhibit 4.1 to the Registrant's Current Report on form 8-K filed on October 27, 2011, File No. 1-9735)
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.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

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* Filed herewith.

** Furnished herewith.

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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: November 3, 2011