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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2011

☐ **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 ☒ NO ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ☒ NO ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

As of July 25, 2011 the registrant had 51,733,091 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 July 25, 2011, all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY
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BERRY PETROLEUM COMPANY

Condensed Balance Sheets

(Unaudited)

(In Thousands, Except Share Information)

	June 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 248	$ 278
Restricted short-term investments	65	65
Accounts receivable	111,023	93,406
Deferred income taxes	34,252	32,342
Derivative instruments	3,129	2,742
Prepaid expenses and other	15,847	14,033
Total current assets	164,564	142,866
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,959,386	2,655,792
Derivative instruments	1,418	2,054
Other assets	34,939	37,904
	$3,160,307	$ 2,838,616
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 105,175	$ 106,459
Revenue and royalties payable	33,492	37,812
Accrued liabilities	29,606	36,234
Line of credit	12,700	5,300
Derivative instruments	60,432	84,846
Total current liabilities	241,405	270,651
Long-term liabilities:		
Deferred income taxes	362,939	329,207
Senior secured revolving credit facility	395,000	170,000
8.25% Senior subordinated notes due 2016	200,000	200,000
10.25% Senior notes due 2014, net of unamortized discount of $9,702 and $11,035, respectively	440,298	438,965
6.75% Senior notes due 2020	300,000	300,000
Asset retirement obligation	56,885	53,443
Derivative instruments	46,470	33,526
Other long-term liabilities	18,136	18,271
	1,819,728	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; 51,604,476 and 51,426,232 shares issued and outstanding, respectively	517	514
Class B Stock, 3,000,000 shares authorized;1,797,784 shares issued and outstanding (liquidation preference of $899)	18	18
Capital in excess of par value	338,397	327,369
Accumulated other comprehensive loss	(24,761)	(43,806)
Retained earnings	785,003	740,458
Total shareholders' equity	1,099,174	1,024,553
	$3,160,307	$ 2,838,616

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

BERRY PETROLEUM COMPANY

Condensed Statements of Operations

(Unaudited)

(In Thousands, Except Per Share Data)

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
REVENUES				
Sales of oil and gas	$ 230,760	$ 151,525	$ 418,149	$ 299,332
Sales of electricity	7,964	7,928	14,376	17,861
Gas marketing	3,985	5,004	7,670	13,276
Settlement of Flying J bankruptcy claim	—	21,992	—	21,992
Interest and other income, net	803	1,796	931	1,960
	243,512	188,245	441,126	354,421
EXPENSES				
Operating costs—oil and gas production	58,780	46,452	115,863	93,488
Operating costs—electricity generation	6,891	7,839	13,004	17,509
Production taxes	8,350	5,064	15,741	10,269
Depreciation, depletion & amortization—oil and gas production	51,967	43,703	104,076	79,609
Depreciation, depletion & amortization—electricity generation	491	793	992	1,588
Gas marketing	3,674	4,357	7,190	12,142
General and administrative	15,910	12,155	32,201	25,990
Interest	17,712	16,340	33,367	33,788
Realized and unrealized (gain) loss on derivatives, net	(91,808)	(56,057)	35,708	(57,661)
Gain on purchase	—	—	(1,046)	—
Transaction costs on acquisitions	—	1,908	—	2,635
Dry hole, abandonment, impairment and exploration	310	266	423	1,636
Bad debt recovery	—	(38,508)	—	(38,508)
	72,277	44,312	357,519	182,485
Earnings before income taxes	171,235	143,933	83,607	171,936
Income tax provision	66,069	54,910	30,938	65,244
Net earnings	$ 105,166	$ 89,023	$ 52,669	$ 106,692
Basic net earnings per share	$ 1.93	$ 1.65	$ 0.97	$ 2.01
Diluted net earnings per share	$ 1.90	$ 1.64	$ 0.95	$ 2.00
Dividends per share	$ 0.075	$ 0.075	$ 0.15	$ 0.15

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

BERRY PETROLEUM COMPANY

Condensed Statements of Cash Flows

(Unaudited)

(In Thousands)

	Six months ended June 30, 2011	Six months ended June 30, 2010
Cash flows from operating activities:		
Net earnings	$ 52,669	$ 106,692
Depreciation, depletion and amortization	105,068	81,197
Gain on purchase	(1,046)	—
Amortization of debt issuance costs and net discount	4,205	4,218
Dry hole and impairment	298	1,428
Derivatives	19,496	(46,110)
Stock-based compensation expense	5,439	5,008
Deferred income taxes	19,572	61,142
Other, net	674	—
Cash paid for abandonment	(864)	(1,535)
Allowance for bad debt	—	(38,508)
Change in book overdraft	4,022	2,007
Changes in operating assets and liabilities:		
Accounts receivable	(18,543)	(27,950)
Inventories, prepaid expenses, and other current assets	(1,813)	(5,226)
Accounts payable and revenue and royalties payable	24,044	(2,687)
Accrued interest and other accrued liabilities	(6,699)	(4,807)
Net cash provided by operating activities	206,522	134,869
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(271,433)	(135,038)
Property acquisitions	(145,461)	(150,674)
Capitalized interest	(18,664)	(13,054)
Net cash used in investing activities	(435,558)	(298,766)
Cash flows from financing activities:		
Proceeds from issuances on line of credit	243,300	159,200
Repayments of borrowings under line of credit	(235,900)	(155,900)
Long-term borrowings under credit facility	357,500	165,000
Repayments of long-term borrowings under credit facility	(132,500)	(227,000)
Financing obligation	(185)	(169)
Debt issuance costs	(677)	—
Dividends paid	(8,124)	(8,083)
Proceeds from issuance of common stock, net	—	224,313
Proceeds from stock option exercises	3,415	1,156
Excess income tax benefit and other	2,177	308
Net cash provided by financing activities	229,006	158,825
Net decrease in cash and cash equivalents	(30)	(5,072)
Cash and cash equivalents at beginning of period	278	5,311
Cash and cash equivalents at end of period	$ 248	$ 239
Noncash investing activities:		
(Decrease) increase in accrued capital expenditures	$ (32,781)	$ 13,486
Increase in asset retirement obligation	1,642	1,860

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

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	3	—	3,412	—	—	3,415
Stock based compensation expense	—	—	5,439	—	—	5,439
Income tax effect of stock option exercises	—	—	2,177	—	—	2,177
Dividends ($0.15 per share)	—	—	—	(8,124)	—	(8,124)
Comprehensive earnings:						
Net earnings	—	—	—	52,669	—	52,669
Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income tax benefit of $11,673	—	—	—	—	19,045	19,045
Total comprehensive earnings	—	—	—	—	—	71,714
Balances at June 30, 2011	$ 517	$ 18	$ 338,397	$ 785,003	$ (24,761)	$ 1,099,174

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

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 June 30, 2011 and December 31, 2010 are $20.3 million and $16.3 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Recent Accounting Standards

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 and requires new disclosures, clarifies existing disclosures 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. The Company anticipates the guidance will have no impact on its 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

1. Basis of Presentation (Continued)

statements of changes in stockholder's equity. Because the ASU requires only a change in disclosures, the guidance will have no impact on the Company's financial position or results of operations.

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 $129.4 million, including an initial purchase price of $128.5 million and customary post-closing adjustments of approximately $0.9 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.

Revenues of $1.4 million and operating costs of $0.3 million from the acquired properties from May 25, 2011 to June 30, 2011 have been included in the accompanying Condensed Statements of Operations.

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed as of May 25, 2011:

	(in thousands)
Consideration paid to sellers:	
Cash consideration	$ 129,376
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed and undeveloped properties	129,631
Asset retirement obligation	(119)
Other liabilities assumed	(136)
Total identifiable net assets	$ 129,376

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 in January 2010 of 8 million shares of the Company's Class A Common Stock, cash generated from operations and net proceeds from the issuance in November 2010 of $300 million aggregate principal amount of the Company's 6.75% senior notes due in November 2020 (2020 Notes).

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

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

2. Acquisitions (Continued)

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.

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 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

3. Debt

Short-Term Line of Credit

The Company has an unsecured uncommitted money market line of credit (Line of Credit) with borrowing capacity of up to $40.0 million for a maximum of 30 days. As of June 30, 2011 and December 31, 2010 there were $12.7 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 June 30, 2011 and December 31, 2010 had weighted average interest rates of 1.6% and 1.7%, respectively.

Senior Secured Revolving Credit Facility

On April 13, 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 remain unchanged at $875 million. 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%

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

3. Debt (Continued)

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 borrowing under the Credit Agreement subject to certain leverage and liquidity tests.

As of June 30, 2011 and December 31, 2010, there were $395 million and $170 million in outstanding borrowings under the Credit Agreement, respectively. The Company's total outstanding debt at June 30, 2011 under the Line of Credit and Credit Agreement was $408 million, with an additional $23 million in letters of credit issued under the Credit Agreement, leaving $444 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.

4. Income Taxes

The effective income tax rate for the three months ended June 30, 2011 and 2010 was 38.6% and 38.1%, respectively. The increase in the effective income tax rate in the three months ended June 30, 2011 compared to the of the three months ended June 30, 2010 is primarily due to the income tax effect of nondeductible stock compensation expense in the three months ended June 30, 2011.

The effective income tax rate for the six months ended June 30, 2011 and 2010 was 37.0% and 37.9%, respectively. The decrease in the effective income tax rate in the six months ended June 30, 2011 compared to the six months ended June 30, 2010 is primarily due to a change in state deferred income taxes as a result of acquisitions, which change the mix of state apportionments. 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 earning that are not expected to reverse in future periods).

As of June 30, 2011, the Company had a gross liability for uncertain income tax benefits of $5.3 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. The Company recognized potential accrued interest and penalties related to unrecognized income tax benefits in income tax expense during the three months ended June 30, 2011, which is consistent with the recognition of these items in prior periods. The Company has accrued approximately $0.9 million and

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

4. Income Taxes (Continued)

$0.8 million of interest related to its uncertain income tax positions as of June 30, 2011 and December 31, 2010, respectively. The Company estimates that it is reasonably possible that the balance of unrecognized income tax benefits as of June 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 Per Share and Comprehensive Earnings

Basic earnings per share is calculated by dividing earnings available to common shareholders by the weighted average shares outstanding—basic during each period. Diluted earnings per share is calculated by dividing earnings 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 per share is required for those entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. 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. Unvested restricted stock issued subsequent to January 1, 2010 under the Company's equity incentive plans does not participate in dividends. Stock options issued under the Company's equity incentive plans do not participate in dividends.

The following table shows the computation of basic and diluted earnings per share for the three and six months ended June 30, 2011 and 2010:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands, except per share data)	**2011**	**2010**	**2011**	**2010**
Net earnings	$ 105,166	$ 89,023	$ 52,669	$ 106,692
Less: earnings allocable to participating securities	1,012	1,713	544	2,133
Earnings available for common shareholders	$ 104,154	$ 87,310	$ 52,125	$ 104,559
Basic earnings per share	$ 1.93	$ 1.65	$ 0.97	$ 2.01
Diluted earnings per share	$ 1.90	$ 1.64	$ 0.95	$ 2.00
Weighted average shares outstanding—basic	54,004	52,965	53,936	52,027
Add: Dilutive effects of stock options and RSUs	704	448	755	380
Weighted average shares outstanding—dilutive	54,708	53,413	54,691	52,407

All options to purchase shares were included in the diluted earnings per share calculation for the three and six months ended June 30, 2011. Options to purchase 0.8 million shares and 1.2 million shares were not included in the diluted earnings per share calculation for the three and six months ended June 30, 2010, respectively, because their effect would have been anti-dilutive.

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

5. Earnings Per Share and Comprehensive Earnings (Continued)

Comprehensive earnings

Comprehensive earnings is a term used to refer to net earnings plus other comprehensive earnings. Other comprehensive earnings is 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:

(in thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Net earnings	$ 105,166	$ 89,023	$ 52,669	$ 106,692
Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income tax benefits of $5,837, $2,478, $11,673, and $4,563, respectively	9,522	4,044	19,045	7,444
Comprehensive earnings	$ 114,688	$ 93,067	$ 71,714	$ 114,136

6. Asset Retirement Obligation

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

(in thousands)	Six months ended June 30, 2011	Six months ended June 30, 2010
Beginning balance at January 1	$ 53,443	$ 43,487
Liabilities incurred	1,642	1,860
Liabilities settled	(864)	(1,534)
Liabilities assumed	119	3,309
Accretion expense	2,545	2,191
Ending balance at June 30	$ 56,885	$ 49,313

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

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

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 (usually the vesting period).

Total compensation cost recognized in the Statements of Operations for the grants under the Company's equity incentive compensation plans was $2.2 million and $1.8 million during the three months ended June 30, 2011 and 2010, respectively, and $5.1 million and $4.1 million during the six months ended June 30, 2011 and 2010, respectively.

Stock Options

The following table summarizes stock option activity for the six months ended June 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	(229,685)	14.93		
Cancelled/expired	—	—		
Outstanding at June 30, 2011	1,877,405	$ 28.29	$ 46,637	1,656,002

(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. The following assumptions were used to compute the weighted average fair market value of options granted:

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

As of June 30, 2011, there was $1.7 million of total unrecognized compensation cost related to outstanding stock options. This cost is expected to be recognized over 3.8 years.

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 six months ended June 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	153,240	47.78	
Issued	(14,515)	38.69	$ 678
Canceled/expired	(3,388)	25.47	
Outstanding at June 30, 2011(1)(2)	992,697	$ 23.70	

(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 294,767 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 June 30, 2011, there was $10.5 million of total unrecognized compensation cost related to RSUs granted. This cost is expected to be recognized over 3.8 years.

Performance Share Program

The following table summarizes performance share award activity for the six months ended June 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	—	—	
Outstanding at June 30, 2011	169,414	$ 39.20	

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. From January 1, 2011 to December 31, 2013, the Company must maintain an interest coverage ratio of at least 2.5 to 1.0. The number of performance share awards that ultimately vest is based on two equally weighted performance factors: (i) compounded annual production growth

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

7. Equity Incentive Compensation Plans (Continued)

as measured by average annual barrels 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 rate	1.15%

As of June 30, 2011, there was $2.3 million of total unrecognized compensation cost related to performance share awards granted. This cost is expected to be recognized over 2.5 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 June 30, 2011, the Company had commodity derivatives associated with the following volumes:

	2011	2012	2013	2014
Oil Bbl/D:	20,020	19,000	13,000	2,000
Natural Gas MMBtu/D:	15,000	15,000	—	—

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 six months ended June 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

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 contract 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 June 30, 2011, AOCL consisted of $39.9 million ($24.8 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 six months ended June 30, 2011, $15.3 million ($9.5 million, net of income tax) and $30.7 million ($19.0 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 $21.5 million related to de-designated commodity and interest rate derivative contracts during the next 12 months.

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

	June 30, 2011			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	$ 3.1	Derivative liabilities	$ 60.4
Long term:				
Commodity	Derivative assets	1.4	Derivative liabilities	46.5
Total derivatives		$ 4.5		$ 106.9

8. Derivative Instruments (Continued)

(in millions)	December 31, 2010 Derivative Assets Balance Sheet Classification	Derivative Assets Fair Value	December 31, 2010 Derivative Liabilities Balance Sheet Classification	Derivative Liabilities 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

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 June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Commodity					
(Gain) loss reclassified from AOCL into earnings (amortization of frozen amounts)	Sales of oil and gas	$ 14.9	$ 4.1	$ 29.5	$ 6.9
(Gain) loss recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized (gain) loss on derivatives, net	(91.8)	(58.8)	35.7	(63.7)
Interest rate					
(Gain) loss reclassified from AOCL into earnings (amortization of frozen amounts)	Interest	$ 0.4	$ 2.4	$ 1.2	$ 5.1
(Gain) loss recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized (gain) loss on derivatives, net	—	2.7	—	6.0

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 June 30, 2011 was $4.5 million.

As of June 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.

Certain of the Company's derivative agreements contain provisions that require cross defaults and acceleration of those instruments to any material debt. If the Company were to default on any of its material debt agreements, it would be a violation of these provisions, and the counterparties to the derivative instruments could request immediate payment on derivative instruments that are in a net liability position at that time. As of June 30, 2011, the Company was in a net liability position with seven of the counterparties to the Company's derivative instruments, totaling $107 million. As of June 30, 2011, the Company's largest three counterparties accounted for 59% 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 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 June 30, 2011 and December 31, 2010:

(in millions)	Total	Level 1	Level 2	Level 3
Commodity derivatives liability, net				
June 30, 2011	$ (102.4)	$ —	$ (102.4)	$ —
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).

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2011	2010	2011	2010
Fair value liability, beginning of period	$ —	$ (34.5)	$ (101.8)	$ (26.0)
Transfers out of Level 3(1)	—	—	101.8	—
Realized and unrealized gain included in earnings	—	41.2	—	41.9
Settlements	—	(10.7)	—	(19.9)
Fair value liability, end of period	$ —	$ (4.0)	$ —	$ (4.0)
Total unrealized gain included in earnings related to financial assets and liabilities still on the Condensed Balance Sheet at June 30, 2011 and 2010	$ —	$ 30.5	$ —	$ 22.0

(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

9. Fair Value Measurements (Continued)

their fair value due to the short-term maturity of these instruments. The carrying amount of the Company's credit facilities approximated fair value because the interest rates on the credit facilities are variable and could be at similar rates today. The fair values of the 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.

	June 30, 2011		December 31, 2010	
(in millions)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Line of credit	$ 13	$ 13	$ 5	$ 5
Senior secured revolving credit facility	395	395	170	170
8.25% Senior subordinated notes due 2016	200	208	200	210
10.25% Senior notes due 2014	440	513	439	518
6.75% Senior notes due 2020	300	300	300	303
	$ 1,348	$ 1,429	$ 1,114	$ 1,206

10. Dry hole, abandonment, impairment and exploration

For the three and six months ended June 30, 2011, the Company incurred dry hole, abandonment, impairment and exploration expense of $0.3 million and $0.4 million, respectively. During the three and six months ended June 30, 2010, the Company incurred dry hole, abandonment, impairment and exploration expense of $0.3 million and $1.6 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 3,500 Bbl/D in the first six 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

11. Commitments and Contingencies (Continued)

financing obligation. A portion of the payments under the agreements are recorded as gathering 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 June 30, 2011 and 2010, the Company incurred $1.4 million and $1.5 million, respectively, under the agreements. For the six months ended June 30, 2011 and 2010, the Company incurred $3.1 million and $2.6 million, respectively, under the agreements.

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

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.

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

Notable Second Quarter 2011 Items

- Generated discretionary cash flow of $121 million from production of 35,600 BOE/D, comprised of 69% oil(1)
- Increased our average production by 13% from the first six months of 2010 and 3% from the first quarter of 2011
- Increased our oil production by 9% from the first quarter of 2011
- Diatomite production averaged 3,550 BOE/D during the second quarter of 2011, up 59% from the first quarter of 2011
- Generated operating margin of $46 per BOE, supported by sales of our California heavy oil at a $5.00 premium to WTI during the quarter(1)
- Invested $145 million to acquire producing properties on approximately 7,000 net acres in the Wolfberry trend, to secure the Wasatch and deep rights at Brundage Canyon and to purchase surface mitigation land needed for asset development in California
- Participated in two Uteland Butte horizontal wells in Lake Canyon, with encouraging results
- Increased our Credit Agreement's borrowing base from $875 million to $1.4 billion in April 2011

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

- Received revised project approval letter from the California Department of Conservation, Division of Oil, Gas & Geothermal Resources (DOGGR) for the full-field development for our Diatomite asset
- Hired John Matson as Vice President of Texas
- Expect to complete 50 Permian wells during the remainder of 2011
- Plan to drill 13 Green River/Wasatch wells in Lake Canyon and six Uteland Butte horizontal wells during the remainder of 2011
- Accelerated the purchase of $20 million of steam generating equipment and emission reduction credits, which are needed to develop our California heavy oil over the next three years

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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 second quarter of 2011, we reported net earnings of $105.2 million, or $1.90 per diluted share, and net cash flows from operations of $107 million. Net earnings includes a gain on derivatives of $64.5 million resulting from non-cash changes in fair values and amortization of accumulated other comprehensive loss (AOCL) related to de-designated hedges.

During the first six months of 2011, we reported net earnings of $52.7 million, or $0.95 per diluted share, and net cash flows from operations of $207 million. Net earnings includes a loss on derivatives of $12.3 million resulting from non-cash changes in fair values and amortization of AOCL related to de-designated hedges.

Operating Data.

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

	June 30, 2011	%	June 30, 2010	%	March 31, 2011	%
Heavy oil production (BOE/D)	17,670	50	17,492	54	16,226	47
Light oil production (BOE/D)	6,959	19	4,377	13	6,422	19
Total oil production (BOE/D)	24,629	69	21,869	67	22,648	66
Natural gas production (Mcf/D)	65,859	31	65,909	33	70,542	34
Total (BOE/D)	35,606	100	32,854	100	34,405	100
Oil and gas, per BOE:						
Average realized sales price	$ 71.07		$ 50.81		$ 60.26	
Average sales price including cash derivative settlements	66.90		53.11		59.01	
Oil, per Bbl:						
Average WTI price	$ 102.34		$ 78.05		$ 94.60	
Price sensitive royalties(1)	(3.85)		(2.90)		(3.56)	
Quality differential and other(2)	(0.83)		(9.71)		(5.68)	
Crude oil derivatives non-cash amortization(3)	(6.72)		(2.42)		(7.07)	
Oil revenue	$ 90.94		$ 63.02		$ 78.29	
Add: Crude oil derivatives non cash amortization(3)	6.72		2.42		7.07	
Crude oil derivative cash settlements(4)	(13.71)		0.01		(10.24)	
Average realized oil price	$ 83.95		$ 65.45		$ 75.12	
Natural gas price:						
Average Henry Hub price per MMBtu	$ 4.32		$ 4.09		$ 4.11	
Conversion to Mcf	0.21		0.20		0.21	
Natural gas derivatives non cash amortization(3)	0.03		0.12		(0.01)	
Location, quality differentials and other	(0.17)		0.02		(0.09)	
Natural gas revenue per Mcf	$ 4.39		$ 4.43		$ 4.22	
Add: Natural gas derivatives non cash amortization(3)	(0.03)		(0.12)		0.01	
Natural gas derivative cash settlements(4)	0.39		0.46		0.41	
Average realized natural gas price per Mcf	$ 4.75		$ 4.77		$ 4.64	

(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 a base price which was $17.09 per barrel during the second quarter of 2011 as long as we maintain a minimum steam injection level. We met the steam injection level in the second 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 June 30, 2011 was $5.61 and ranged from a low of $4.77 to a high of $5.61 per barrel during the second quarter of 2011. In Utah, the oil posting differential at June 30, 2011 was ($14.00) and averaged ($14.48) during the second quarter of 2011.

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

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

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

	June 30, 2011	%	June 30, 2010	%
Heavy oil production (BOE/D)	16,951	49	17,621	57
Light oil production (BOE/D)	6,714	19	3,570	11
Total oil production (BOE/D)	23,665	68	21,191	68
Natural gas production (Mcf/D)	68,188	32	59,644	32
Total (BOE/D)	35,030	100	31,132	100
Oil and gas, per BOE:				
Average realized sales price	$ 65.78		$ 53.24	
Average sales price including cash derivative settlements	63.04		54.98	
Oil, per Bbl:				
Average WTI price	$ 98.50		$ 78.46	
Price sensitive royalties(1)	(3.71)		(2.97)	
Quality differential and other(2)	(3.00)		(8.95)	
Crude oil derivatives non-cash amortization(3)	(6.89)		(2.08)	
Oil revenue	$ 84.90		$ 64.46	
Add: Crude oil derivatives non cash amortization(3)	6.89		2.08	
Crude oil derivative cash settlements(4)	(12.06)		(0.10)	
Average realized oil price	$ 79.73		$ 66.44	
Natural gas price:				
Average Henry Hub price per MMBtu	$ 4.21		$ 4.70	
Conversion to Mcf	0.21		0.24	
Natural gas derivatives non cash amortization(3)	0.01		0.10	
Location, quality differentials and other	(0.13)		(0.13)	
Natural gas revenue per Mcf	$ 4.30		$ 4.91	
Add: Natural gas derivatives non cash amortization(3)	(0.01)		(0.10)	
Natural gas derivative cash settlements(4)	0.40		0.30	
Average realized natural gas price per Mcf	$ 4.69		$ 5.11	

(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 a base price which was $17.09 per barrel during the first six months of 2011 as long as we maintain a minimum steam injection level. We met the steam injection level in the first six 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 June 30, 2011 was $5.61 and ranged from a low of ($6.43) to a high of $5.61 per barrel during the first six months of 2011. In Utah, the oil posting differential at June 30, 2011 was ($14.00) and averaged ($14.74) during the first six months of 2011.

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

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

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

	June 30, 2011	June 30, 2010	2Q10 to 2Q11 Change	March 31, 2011	1Q11 to 2Q11 Change
Sales of oil	$ 205	$ 125	64%	$ 160	28%
Sales of gas	26	27	(4)%	27	(4)%
Total sales of oil and gas	$ 231	$ 152	52%	$ 187	24%
Sales of electricity	8	8	—	7	14%
Gas marketing	4	5	(20)%	4	—
Settlement on Flying J bankruptcy claim	—	22	(100)%	—	—
Interest and other income, net	1	1	—	—	100%
Total revenues and other income	$ 244	$ 188	30%	$ 198	23%
Net earnings (loss)	$ 105	$ 89	—	$ (52)	—
Diluted earnings (loss) per share	$ 1.90	$ 1.64	—	$ (0.98)	—

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

	June 30, 2011	June 30, 2010	% Change
Sales of oil	$ 365	$ 246	48%
Sales of gas	53	53	—
Total sales of oil and gas	$ 418	$ 299	40%
Sales of electricity	14	18	(22)%
Gas marketing	8	13	(38)%
Settlement on Flying J bankruptcy claim	—	22	(100)%
Interest and other income, net	1	2	(50)%
Total revenues and other income	$ 441	$ 354	25%
Net earnings	$ 53	$ 107	—
Diluted earnings per share	$ 0.95	$ 2.00	—

Sales of Oil and Gas.

Sales of oil and gas increased $79 million, or 52%, to $231 million in the second quarter of 2011 compared to $152 million in the second quarter of 2010. The increase is due to a 9% increase in sales volumes along with a 40% increase in the average realized sales price from the second quarter of 2010 to the second quarter of 2011. Sales of oil and gas increased $44 million, or 24%, to $231 million in the second quarter of 2011 compared to $187 million in the first quarter of 2011. The increase is due to a 4% increase in sales volumes and an 18% increase in the average realized sales price period over period. Sales of oil and gas for the second quarter of 2011 include non-cash amortization of AOCL related to de-designated hedges of $4.61 per BOE compared to $1.37 per BOE in the second quarter of 2010 and $4.68 per BOE in the first quarter of 2011.

Sales of oil and gas increased $119 million, or 40%, to $418 million for the six months ended June 30, 2011 compared to $299 million in the six months ended June 30, 2010. The increase is due to a 13% increase in sales volumes along with a 24% increase in the average realized sales price in the six months ended June 30, 2011 compared to the six months ended June 30, 2010. Sales of oil and gas for the six months ended June 30, 2011 include non-cash amortization of AOCL related to de-designated hedges of $4.64 per BOE compared to $1.23 per BOE in the six months ended June 30, 2010.

Approximately 69% of our oil and gas sales volumes in the second quarter of 2011 were oil, with 72% 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 six month periods ended:

	Three months ended			Six months ended	
	June 30, 2011	June 30, 2010	March 31, 2011	June 30, 2011	June 30, 2010
Electricity					
Revenues (in millions)	$ 8.0	$ 7.9	$ 6.4	$ 14.4	$ 17.9
Operating costs (in millions)	$ 6.9	$ 7.8	$ 6.1	$ 13.0	$ 17.5
Electric power produced—MWh/D	1,969	2,009	1,856	1,912	2,081
Electric power sold—MWh/D	1,810	1,840	1,689	1,750	1,909
Average sales price/MWh	$ 48.34	$ 47.47	$ 42.17	$ 45.38	$ 53.18
Fuel gas cost/MMBtu (including transportation)	$ 4.53	$ 4.30	$ 4.33	$ 4.43	$ 4.91

Sales of electricity in the second quarter of 2011 were consistent with sales of electricity in the second quarter of 2010 due to a 2% decrease in electric power sold offset by a 2% increase in the average sales price of electricity. Electricity operating costs decreased in the second quarter of 2011 compared to the second quarter of 2010 primarily due to a 2% decrease in electric power produced. Sales of electricity increased 25% in the second quarter of 2011 compared to the first quarter of 2011 primarily due to a 15% increase in the average sales price of electricity and a 7% increase in electric power sold due to increased production in the second quarter of 2011 from one of our three cogeneration facilities, which was shut down for scheduled maintenance during March 2011. Electricity operating costs increased 13% in the second quarter of 2011 compared to the first quarter of 2011 primarily due to a 6% increase in electric power produced and a 5% increase in fuel gas cost. We purchased approximately 25,000, 26,000 and 23,000 MMBtu/D of natural gas as fuel for use in our cogeneration facilities for the three months ended June 30, 2011, June 30, 2010 and March 31, 2011, respectively.

Sales of electricity decreased 20% in the six months ended June 30, 2011 compared to the six months ended June 30, 2010 due to a 15% decrease in the average sales price and an 8% 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 26% in the six months ended June 30, 2011 compared to the six months ended June 30, 2010 due to an 8% decrease in electric power produced and a 10% 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 cost (SRAC), which reflected an avoidance of capital expenditures that would otherwise have been made by the utility to construct or procure equivalent capacity, or short-term avoided costs.

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 order granting the IOU's application became final and nonappealable on July 18, 2011, satisfying the final condition to the effectiveness of the Global Settlement. However, the effectiveness of the Global Settlement is on hold pending resolution of certain procedural issues raised by interim changes made by an administrative law judge to the language of the proposed CPUC decision affirming the effectiveness of the Global Settlement. The parties to the settlement recently filed with the CPUC a petition to modify the language of the proposed CPUC decision and have requested the CPUC to consider the petition at either its August or September 2011 meeting. If the CPUC grants the petition, the settling parties have requested the CPUC to establish the effective date of Global Settlement as the date on which the CPUC decision granting the petition becomes final and non-appealable, being at least 30 days following the grant.

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 October 2011.

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 higher than the current SRAC pricing for the remainder of 2011, and 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 for our Piceance natural gas production, 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 purchased our co-working interest owners' working interest 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. The Rockies Express pipeline moves the gas to a location near Lebanon, Ohio where we receive a price based on that sales point.

Additionally, we have firm transportation contracts on the Ruby Pipeline from Opal, WY to Malin, OR for an average total capacity of 35,000 MMBtu/D for 10 years. These contracts, which became effective July 28, 2011, require a minimum monthly charge regardless of whether the contracted capacity is used or not. At the present time, our own production is insufficient to fully utilize this capacity; therefore, we entered into FERC-approved Asset Management Agreements with a marketer whereby the marketer optimizes our unfilled capacity. Demand charges paid under both our Rockies Express 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 June 30, 2011 and 2010 is $0.3 million and $0.6 million, respectively. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Operations for the six months ended June 30, 2011 and 2010 is $0.5 million and $1.1 million, respectively. Firm transportation costs related to our Rockies Express pipeline volumes are reflected in Operating costs—oil and gas production and total $4.1 million and $3.7 million for the three months ended June 30, 2011 and 2010, respectively, and $8.1 million and $6.9 million for the six months ended June 30, 2011 and 2010, respectively.

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)		
	June 30, 2011	June 30, 2010	March 31, 2011	June 30, 2011	June 30, 2010	March 31, 2011
Operating costs—oil and gas production	$ 18.14	$ 15.54	$ 18.44	$ 58,780	$ 46,452	$ 57,083
Production taxes	2.58	1.69	2.39	8,350	5,064	7,391
DD&A—oil and gas production	16.04	14.62	16.83	51,967	43,703	52,109
General and administrative	4.91	4.07	5.26	15,910	12,155	16,291
Interest expense	5.47	5.47	5.06	17,712	16,340	15,655
Total	$ 47.14	$ 41.39	$ 47.98	$ 152,719	$ 123,714	$ 148,529

- Operating costs in the second quarter of 2011 were $58.8 million, or $18.14 per BOE, compared to $46.5 million, or $15.54 per BOE, in the second quarter of 2010 and $57.1 million, or $18.44 per BOE, in the first quarter of 2011. The increase in operating costs per BOE in the second quarter of 2011 compared to the second quarter of 2010 is primarily due to increased steam costs, as well as increased costs for contract services and well workovers. The decrease in operating costs per BOE in the second quarter of 2011 compared to the first quarter of 2011 is primarily due to a 5% increase in production in the second quarter of 2011 compared to the first quarter of 2011 and the inclusion of a $1.3 million proposed legal settlement accrual in the first quarter of 2011, partially offset by increased costs for steam and contract services. 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:

	June 30, 2011 (2Q11)	June 30, 2010 (2Q10)	2Q10 to 2Q11 Change	March 31, 2011 (1Q11)	1Q11 to 2Q11 Change
Average volume of steam injected (Bbl/D)	141,334	110,467	28%	120,612	17%
Fuel gas cost/MMBtu (including transportation)	$ 4.53	$ 4.30	5%	$ 4.33	5%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	45,890	33,501	37%	39,552	16%

- Production taxes in the second quarter of 2011 were $8.4 million, or $2.58 per BOE, compared to $5.1 million, or $1.69 per BOE, in the second quarter of 2010 and $7.4 million, or $2.39 per BOE, in the first 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 in the second quarter of 2011 per BOE compared to the second quarter of 2010 was primarily due to an increase in the assessed ad valorem values attributable to our California properties. In addition, our Permian and Utah properties contributed to higher production taxes per BOE due to severance taxes being tied to field sales prices. The increase in production taxes in the second quarter of 2011 per BOE compared to the first quarter of 2011 was primarily due to increased production from our Permian and Utah properties, where severance taxes are tied to field sales prices.

- Depreciation, depletion and amortization (DD&A) related to oil and gas production in the second quarter of 2011 was $52.0 million, or $16.04 per BOE, compared to $43.7 million, or $14.62 per BOE, in the second quarter of 2010 and $52.1 million, or $16.83 per BOE, in the first quarter of 2011. The increase in DD&A per BOE in the second quarter of 2011 compared to the second quarter of 2010 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. The decrease in DD&A per BOE in the second quarter of 2011 compared to the first quarter of 2011 is due to an increase in our production from our California assets, where we have a lower DD&A rate, relative to our other assets.

- General and administrative expense (G&A) in the second quarter of 2011 was $15.9 million, or $4.91 per BOE, compared to $12.2 million, or $4.07 per BOE, in the second quarter of 2010 and $16.3 million, or $5.26 per BOE, in the first quarter of 2011. The increase in G&A expenses per BOE in the second quarter of 2011 compared to the second 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, principally related to our acquired properties. The decrease in G&A expenses per BOE in the second quarter of 2011 compared to the first quarter of 2011 was due to a decrease in stock-based compensation from the first quarter of 2011. Additionally, average production increased 3% over the same time period. The decrease was partially offset by increases in consulting, property evaluation, legal and accounting fees.

- Interest expense in the second quarter of 2011 was $17.7 million or $5.47 per BOE compared to $16.3 million, or $5.47 per BOE, in the second quarter of 2010 and $15.7 million, or $5.06 per BOE, in the first quarter of 2011. The increase in interest expense in the second quarter of 2011 compared to the second quarter of 2010 was due to an increase in the amount outstanding under the Credit Agreement and the addition of $300 million in aggregate principal amount of our 6.75% senior notes due 2020 (2020 Notes), offset by a decrease $0.69 per BOE in the non-cash amortization of AOCL related to de-designated hedges and an increase in capitalized interest principally due to the recent Permian acquisitions. The increase in interest expense in the second quarter of 2011 compared to the first quarter of 2011 was primarily due to a decrease in capitalized interest related to the deferral of drilling activity in the Piceance.

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

	Amount per BOE		Amount (in thousands)	
	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
Operating costs—oil and gas production	$ 18.27	$ 16.59	$ 115,863	$ 93,488
Production taxes	2.48	1.82	15,741	10,269
DD&A—oil and gas production	16.41	14.13	104,076	79,609
General and administrative	5.08	4.61	32,201	25,990
Interest expense	5.26	6.00	33,367	33,788
Total	$ 47.50	$ 43.15	$ 301,248	$ 243,144

- Operating costs in the six months ended June 30, 2011 were $115.9 million or $18.27 per BOE, compared to $93.5 million or $16.59 per BOE in the six months ended June 30, 2010. The increase in operating costs per BOE in the first six months of 2011 compared to the first six months of 2010 is primarily due to increased steam costs, increased costs for contract services, higher well workover costs and increased well maintenance 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 six months ended:

	June 30, 2011	June 30, 2010	Change
Average volume of steam injected (Bbl/D)	130,250	114,577	14%
Fuel gas cost/MMBtu (including transportation)	$ 4.43	$ 4.91	(10)%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	42,743	35,097	22%

- Production taxes in the six months ended June 30, 2011 were $15.7 million, or $2.48 per BOE, compared to $10.3 million, or $1.82 per BOE, in the six months ended June 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 six months ended June 30, 2011 compared to the six months ended June 30, 2010 is due to the added production in Utah and Texas and an increase in the assessed ad valorem values attributed to our California properties.

- DD&A in the six months ended June 30, 2011 was $104.1 million, or $16.41 per BOE, compared to $79.6 million, or $14.13 per BOE, in the six months ended June 30, 2010. The increase per BOE is primarily due to the increase in production from assets outside of California, which have higher per barrel DD&A rates than our California properties.

- G&A in the six months ended June 30, 2011 was $32.2 million, or $5.08 per BOE, compared to $26.0 million, or $4.61 per BOE in the six months ended June 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, consulting, property evaluation, accounting and legal fees increased during the same time period.

- Interest expense in the six months ended June 30, 2011 was $33.4 million, or $5.26 per BOE, compared to $33.8 million, or $6.00 per BOE, in the six months ended June 30, 2010. The decrease in interest expense in the six months ended June 30, 2011 compared to the six months ended June 30, 2010 was due to a decrease of $0.72 per BOE in the non-cash amortization of AOCL related to de-designated hedges and an increase in capitalized interest related to recent Permian acquisitions. These decreases were offset by additional interest related to an increase in the average amount outstanding under the Credit Agreement and the addition of $300 million aggregate principal amount of our 2020 Notes.

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 also 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.

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

(in thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Three months ended March 31, 2011	Six months ended June 30, 2011	Six months ended June 30, 2010
Cash (receipts) payments:					
Commodity derivatives—oil	$ 30,831	$ (21)	$ 21,009	$ 51,840	$ 393
Commodity derivatives—natural gas	(2,319)	(2,757)	(2,592)	(4,911)	(3,274)
Financial derivatives—interest	—	1,829	—	—	3,655
Total cash (receipts) payments	$ 28,512	$ (949)	$ 18,417	$ 46,929	$ 774
Mark-to-market (gain) loss:					
Commodity derivatives—oil	$ (121,013)	$ (58,852)	$ 107,089	$ (13,924)	$ (51,741)
Commodity derivatives—natural gas	693	2,888	2,010	2,703	(9,051)
Financial derivatives—interest	—	856	—	—	2,357
Total mark-to-market (gain) loss	$ (120,320)	$ (55,108)	$ 109,099	$ (11,221)	$ (58,435)
Total realized and unrealized (gain) loss on derivatives, net	$ (91,808)	$ (56,057)	$ 127,516	$ 35,708	$ (57,661)

Gain on purchase.

For the three months ended March 31, 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 during that period 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.

For the three and six months ended June 30, 2010, transaction costs on acquisitions were $1.9 million and $2.6 million, respectively. In the three and six months ended June 30, 2010, we recorded $0.5 million and $2.6 million of acquisition related expenses, respectively, for the acquisition of certain properties in the Permian. Our preliminary purchase price allocation for our March 2010 acquisition included an estimate for the activity between January 1, 2010 and March 4, 2010; however, actual amounts were greater than our estimate, which resulted in an increase to the total cash consideration paid to the seller. As a result, the $1.4 million Gain on purchase of oil and natural gas properties recorded in the first quarter of 2010 was reversed in the second quarter of 2010 to reflect the purchase price adjustments.

Dry hole, abandonment, impairment and exploration.

For the three and six months ended June 30, 2011, we incurred dry hole, abandonment, impairment and exploration expense of $0.3 million and $0.4 million, respectively. For the three and six months ended June 30, 2010, we incurred dry hole, abandonment, impairment and exploration expense of $0.3 million and $1.6 million, respectively. The cost recognized in the six months ended June 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.

Income Tax Expense.

The effective income tax rate for the three months ended June 30, 2011 and 2010 was 38.6% and 38.1%, respectively. The increase in the effective income tax rate in the three months ended June 30, 2011 compared to the three months ended June 30, 2010 is primarily due to the income tax effect of nondeductible stock compensation expense in the three months ended June 30, 2011.

The effective income tax rate for the six months ended June 30, 2011 and 2010 was 37.0% and 37.9%, respectively. The decrease in the effective income tax rate in the six months ended June 30, 2011 compared to the six months ended June 30, 2010 is primarily due to a change in state deferred income taxes as a result of acquisitions, which change the mix of state apportionments. 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):

	Three months ended June 30, 2011		Six months ended June 30, 2011	
Asset Team	Gross Production Wells	Net Production Wells	Gross Production Wells	Net Production Wells
SMWSS Steam Floods	22	22	34	34
NMWSS—Diatomite	29	29	105	105
Permian	28(1)	21	49(3)	35
Uinta	17(2)	15	27(2)	25
E. Texas	—	—	—	—
Piceance	—	—	5	5
Totals	96	87	220	204

(1) Includes five wells in which we have an average interest of approximately 0.7% each, or approximately 0.03 total net wells.
(2) Includes two wells in which we have an average interest of 18.75% each, or approximately 0.40 total net wells.
(3) Includes 11 wells in which we have an average interest of approximately 0.7% each, or approximately 0.07 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 second quarter of 2011, we drilled 22 gross (22 net) productive wells, including three horizontal producers at Homebase, two vertical producers at Formax, two vertical producers at Poso Creek and 15 vertical producers at Ethel D. These new wells are currently online or undergoing their first steam cycle. Average daily production in the second quarter of 2011 from all of our SMWSS—Steam Floods assets was approximately 13,150 BOE/D

NMWSS—Diatomite—Our NMWSS—Diatomite asset team includes our Diatomite, McKittrick and other associated properties in NMWSS. During the first quarter of 2011, we drilled 19 gross (19 net) Diatomite wells. Our Diatomite production in the second quarter of 2011 averaged 3,550 BOE/D, an increase of 59% from the first quarter of 2011. During July 2011, we received a revised project approval letter from the DOGGR for the full-field development of our Diatomite asset. In the remainder of 2011, we plan to drill 50 wells in the Diatomite. We drilled 10 gross (10 net) productive wells at our other NMWSS properties. We expect to begin the next phase of drilling in McKittrick in the third quarter of 2011 with a 44-well drilling program. Average daily production from all of our NMWSS—Diatomite assets in the second quarter of 2011 was approximately 4,510 BOE/D, a 45% increase from the first quarter of 2011.

Permian—During the second quarter of 2011, a fifth rig was added to the Permian drilling program and 23 gross wells were drilled (21 net). Our drilling inventory in the Permian is approximately 460 locations on 40-acre spacing. Average daily production in the second quarter of 2011 from our Permian assets averaged 3,850 BOE/D, a 29% increase from the first quarter of 2011.

Uinta—During the second quarter of 2011, we drilled 15 gross wells (15 net), including eight wells in Brundage Canyon and seven wells in Ashley Forest. At the end of the second quarter, we spudded our first 2011 Green River/Wasatch well in Lake Canyon, with additional wells scheduled to be drilled in the third quarter. We also participated in two Uteland Butte horizontal wells in Lake Canyon with our industry partner, and we are encouraged with the results. We expect to spud our first Uteland Butte horizontal well in August 2011 and drill three total Uteland Butte horizontal wells before year-end. Our industry partner plans three additional Uteland Butte horizontal wells during 2011. In the second quarter of 2011, the Forest Service approved categorical exclusions for 18 additional wells in Ashley Forest. The Environmental Impact Study continues to progress, with final approval anticipated in 2011. Average daily production from our Uinta assets averaged 5,620 BOE/D, a 2% increase from the first quarter of 2011.

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 second quarter of 2011 from the E. Texas assets was 27 MMcf/D.

Piceance—During the second quarter of 2011, we completed two wells and have five more wells to complete during the remainder of 2011. 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 second quarter of 2011 from the Piceance assets was 24 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 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 June 30, 2011, we have approximately 75% and 55% 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 concerning 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 remain unchanged at $875 million. 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 facility to between 0.35% and 0.50%.

The amendment also provides the right for us to refinance our 10.25% senior notes due in 2014 (2014 Notes) and 8.25% senior notes due in 2016 (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.

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 million for a maximum of 30 days under our Line of Credit. Our total outstanding debt at June 30, 2011 under the Line of Credit and Credit Agreement was $408 million, with an additional $23 million in letters of credit issued under the Credit Agreement, leaving $444 million in borrowing capacity available.

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 June 30, 2011, we had a working capital deficit of approximately $76.8 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 $71.7 million in the first six months of 2011 compared to the first six months of 2010 is primarily due to increased production and higher realized commodity sales prices.

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 six months of 2011 compared to the first six months of 2010 is primarily due to an increase of $136 million in cash used for the exploration and development of our oil and gas properties in the first six months of 2011 compared to the first six months of 2010.

Financing Activities—Net cash provided by financing activities in the first six months of 2011 included net borrowings under our Credit Agreement and Line of Credit of $232 million. Net cash provided by financing activities in the first six 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 $58.7 million and dividends paid of $8.1 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 during 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, requires new disclosures and clarifies existing disclosures 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. We anticipate the guidance will have no 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. Because the ASU requires only a change in disclosures, the guidance will have no impact on our financial position or results of operations.

Reconciliation of Non-GAAP Measures.

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

(in millions)	Three Months Ended June 30, 2011	Six Months Ended June 30, 2011
Net cash provided by operating activities	$ 107	$ 207
Add back: Net increase in current assets	5	20
Add back: Net decrease (increase) in current liabilities including book overdraft	9	(21)
Discretionary cash flow	$ 121	$ 206

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 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 June 30, 2011	Six Months Ended June 30, 2011
Average sales price including cash derivative settlements	$ 66.90	$ 63.04
Average operating costs—oil and gas production	18.14	18.27
Average production taxes	2.58	2.48
Average operating margin	$ 46.18	$ 42.29

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 June 30, 2011, we have approximately 75% and 55% 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 June 30, 2011 would decrease the respective fair value of crude oil and natural gas derivative instruments at June 30, 2011 by $119 million and $5 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 June 30, 2011 would increase the respective fair value of crude oil and natural gas derivative instruments at June 30, 2011 by $104 million and $5 million, respectively.

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

Term	Average Barrels/MMBtu Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Collars		
Full year 2011	270	$80.00/$90.00
Full year 2011	1,000	$55.20/$70.00
Full year 2011	1,000	$55.00/$70.50
Full year 2011	1,000	$55.00/$68.65
Full year 2011	1,000	$55.00/$68.00
Full year 2011	1,000	$55.00/$71.20
Full year 2011	1,000	$60.00/$76.00
Full year 2011	1,000	$60.00/$81.25
Full year 2011	500	$75.00/$101.15
Full year 2011	500	$75.00/$100.75
Full year 2011	1,000	$75.00/$91.25
Full year 2012	1,000	$63.00/$82.60
Full year 2012	1,000	$63.00/$83.50
Full year 2012	1,000	$70.00/$93.00
Full year 2012	500	$75.00/$106.00
Full year 2012	500	$75.00/$105.00
Full year 2012	1,000	$75.00/$95.00
Crude Oil Sales (NYMEX WTI) Swaps		
Full year 2011	500	$57.36
Full year 2011	500	$57.40
Full year 2011	500	$57.50
Full year 2011	250	$61.80
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2011	5,000	$6.89
Full year 2011	5,000	$5.50
Full year 2012	5,000	$7.16
Full year 2012	5,000	$5.75
Natural Gas Sales (NYMEX HH) Collars		
Full year 2011	5,000	$6.00/$7.25
Full year 2012	5,000	$6.00/$7.70
Natural Gas Sales (NYMEX HH to NGPL-Tex OK) Basis		
Full year 2011	2,500	$0.46
Full year 2012	2,500	$0.44
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2011	2,500	$0.33
Full year 2012	2,500	$0.32

Term	Average Barrels Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2011	500	$65.00/$85.00/$97.25
Full year 2011	1,000	$70.00/$87.00/$105.00
Full year 2011	1,000	$55.00/$75.00/$91.63
Full year 2011	1,000	$60.00/$80.00/$101.00
Full year 2011	1,000	$70.00/$88.15/$100.00
Full year 2011	1,000	$70.00/$86.85/$100.00
Full year 2011	1,000	$69.70/$85.00/$100.00
Full year 2011	500	$70.00/$85.00/$94.68
Feb-Dec 2011	1,000	$70.00/$90.00/$116.50
Jun-Dec 2011	1,000	$77.95/$105.00/$115.00
Full year 2012	1,000	$65.00/$85.00/$97.25
Full year 2012	1,000	$70.00/$87.00/$105.00
Full year 2012	1,000	$70.00/$88.00/$106.00
Full year 2012	1,000	$60.00/$80.00/$96.92
Full year 2012	1,000	$60.00/$80.00/$120.00
Full year 2012	1,000	$70.00/$88.15/$100.00
Full year 2012	1,000	$70.00/$86.85/$100.00
Full year 2012	1,000	$69.70/$85.00/$100.00
Full year 2012	1,000	$70.00/$87.00/$108.50
Full year 2012	1,000	$70.00/$90.00/$116.50
Full year 2012	1,000	$70.00/$90.00/$120.00
Full year 2012	1,000	$70.00/$95.00/$120.10
Full Year 2012	1,000	$77.95/$105.00/$115.00
Full Year 2012	1,000	$80.00/$107.00/$119.60
Full year 2013	1,000	$65.00/$85.00/$97.25
Full year 2013	1,000	$70.00/$87.00/$105.00
Full year 2013	1,000	$70.00/$88.00/$106.00
Full year 2013	1,000	$60.00/$80.00/$103.30
Full year 2013	1,000	$70.00/$88.15/$100.00
Full year 2013	1,000	$70.00/$86.85/$100.00
Full year 2013	1,000	$69.70/$85.00/$100.00
Full year 2013	1,000	$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 2014	1,000	$77.95/$105.00/$115.00
Full year 2014	1,000	$80.00/$107.00/$119.60

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 June 30, 2011, our outstanding principal balance under our Credit Agreement was $395 million and the weighted average interest rate on the outstanding principal balance was 2.0%. At June 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 $2.6 million over a 12-month time period.

Item 4. Controls and Procedures

As of June 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 June 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 June 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".

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

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.

Item 6. Exhibits

Exhibit No.	Description of Exhibit
4.1	First Amendment to the Second Amended and Restated Credit Agreement dated April 13, 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 April 13, 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

* Filed herewith.

** Furnished herewith.

SIGNATURE

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

BERRY PETROLEUM COMPANY

/s/ JAMIE L. WHEAT

Jamie L. Wheat
Controller
(Principal Accounting Officer)
Date: August 5, 2011

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Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in thousands, except ratios)

	Six Months Ended June 30, 2011	For the Year Ended 12/31/2010	12/31/2009	12/31/2008	12/31/2007	12/13/2006
Pre-tax income from continuing operations	$ 83,607	$ 136,492	$ 67,888	$ 190,193	$ 195,616	$ 158,191
Interest expense	33,367	66,541	50,738	26,209	17,287	10,247
Amortization of Capitalize Interest	868					
Capitalized interest	18,664	28,321	30,107	23,209	18,104	9,339
Earnings	$ 117,843	$ 203,033	$ 118,626	$ 216,402	$ 212,903	$ 168,438
Ratio of earnings to fixed charges	2.26	2.14	1.47	4.38	6.02	8.60

For purposes of this table, "earnings" consists of income before income taxes from continuing operations plus fixed charges and less capitalized interest. "Fixed charges" consists of interest expense and capitalized interest (for both continuing and discontinued operations).

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Exhibit 31.1

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, certify that:

1. I have reviewed this report on Form 10-Q of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, and its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

	/s/ ROBERT F. HEINEMANN
August 5, 2011	Robert F. Heinemann President, Chief Executive Officer and Director

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Exhibit 31.2

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, David D. Wolf, certify that:

1. I have reviewed this report on Form 10-Q of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

/s/ DAVID D. WOLF

August 5, 2011

David D. Wolf
Executive Vice President and Chief Financial Officer

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Exhibit 31.2

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Exhibit 32.1

Certification of Chief Executive Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the "Company") on Form 10-Q for the period ending June 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

	/s/ ROBERT F. HEINEMANN
August 5, 2011	Robert F. Heinemann President, Chief Executive Officer and Director

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Exhibit 32.2

Certification of Chief Financial Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the "Company") on Form 10-Q for the period ending June 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David D. Wolf, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ DAVID D. WOLF

David D. Wolf
Executive Vice President and Chief Financial Officer

August 5, 2011

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Exhibit 32.2