BERRY PETROLEUM CO
Form 10-Q
April 27, 2012
Use these links to rapidly review the document
TABLE OF CONTENTS

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
T Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended March 31, 2012
o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to

Commission file number 1-9735
BERRY PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

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

1999 Broadway, Suite 3700
Denver, Colorado 80202
(Address of principal executive offices, including zip code)
Registrant's telephone number, including area code: (303) 999-4400
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES T 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 T 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 T	Accelerated filer £	Non-accelerated filer £ (Do not check if a smaller reporting company)	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 T
As of April 16, 2012 the registrant had 52,346,993 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 April 16, 2012, all of which is held by a single holder.

Table of Contents

BERRY PETROLEUM COMPANY
INDEX TO FORM 10-Q
March 31, 2012

BERRY PETROLEUM COMPANY
Condensed Balance Sheets
(Unaudited)
(In Thousands, Except Share Information)

	March 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$43,996	$298
Restricted short-term investments	65	65
Accounts receivable	123,385	115,952
Deferred income taxes	18,973	13,779
Derivative instruments	283	6,117
Assets held for sale	—	14,622
Prepaid expenses and other	19,487	16,801
Total current assets	206,189	167,634
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	2,650,904	2,531,393
Derivative instruments	276	7,027
Other assets	36,831	28,898
	$2,894,200	$2,734,952
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		

Accounts payable	$129,300	$126,489
Revenue and royalties payable	25,412	49,253
Accrued liabilities	52,758	35,066
Derivative instruments	44,740	20,365
Total current liabilities	252,210	231,173
Long-term liabilities:		
Deferred income taxes	207,992	185,450
Senior secured revolving credit facility	—	531,500
8.25% Senior subordinated notes due 2016	200,000	200,000
10.25% Senior notes due 2014, net of unamortized discount of $5,966 and $6,564, respectively	349,290	348,692
6.75% Senior notes due 2020	300,000	300,000
6.375% Senior notes due 2022	600,000	—
Asset retirement obligation	69,064	64,019
Derivative instruments	19,338	15,505
Other long-term liabilities	17,769	17,884
	1,763,453	1,663,050
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; 52,346,993 and 52,067,994 shares issued and outstanding, respectively	524	521
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $0.50 per share)	18	18
Capital in excess of par value	357,179	350,158
Accumulated other comprehensive loss	(4,250)	(5,517)
Retained earnings	525,066	495,549
Total shareholders' equity	878,537	840,729
	$2,894,200	$2,734,952

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 March 31,	
	2012	2011
REVENUES		
Sales of oil and natural gas	$233,653	$187,389
Sales of electricity	5,980	6,412
Natural gas marketing	1,859	3,685
Gain on sale of assets	1,763	—
Interest and other income, net	747	128
	244,002	197,614
EXPENSES		
Operating costs—oil and natural gas production	54,252	57,083
Operating costs—electricity generation	5,017	6,113
Production taxes	10,658	7,391
Depreciation, depletion & amortization—oil and natural gas production	47,956	52,109
Depreciation, depletion & amortization—electricity generation	466	501

Natural gas marketing	1,777	3,516
General and administrative	17,741	16,291
Interest	20,104	15,655
Dry hole, abandonment, impairment and exploration	3,036	113
Gain on purchase	—	(1,046)
Realized and unrealized loss on derivatives, net	28,481	127,516
	189,488	285,242
Earnings (loss) before income taxes	54,514	(87,628)
Income tax provision (benefit)	20,616	(35,131)
Net earnings (loss)	$33,898	$(52,497)
Basic net earnings (loss) per share	$0.62	$(0.98)
Diluted net earnings (loss) per share	$0.61	$(0.98)
Dividends per share	$0.080	$0.075

The accompanying notes are an integral part of these Condensed Financial Statements.

BERRY PETROLEUM COMPANY
Condensed Statements of Comprehensive Earnings (Loss)
(Unaudited)
(In Thousands)

	Three Months Ended March 31,	
	2012	2011
Net earnings (loss)	$33,898	$(52,497)
Other comprehensive earnings, net of tax:		
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income tax benefits of $777 and $5,836, respectively	1,267	9,523
Other comprehensive earnings	1,267	9,523
Comprehensive earnings (loss)	$35,165	$(42,974)

The accompanying notes are an integral part of these Condensed Financial Statements.

BERRY PETROLEUM COMPANY
Condensed Statements of Cash Flows
(Unaudited)
(In Thousands)

	Three Months Ended March 31,	
	2012	2011
Cash flows from operating activities:		
Net earnings (loss)	$33,898	$(52,497)
Depreciation, depletion and amortization	48,422	52,610
Gain on sale of assets	(1,763)	—
Gain on purchase	—	(1,046)
Amortization of debt issuance costs and net discount	2,037	2,099
Dry hole and impairment	28	—
Derivatives	42,837	124,459
Stock-based compensation expense	3,104	3,052
Deferred income taxes	16,567	(44,321)
Other, net	683	576

Allowance for bad debt	315	—
Change in book overdraft	(509)	4,736
Changes in operating assets and liabilities:		
Accounts receivable	(7,835)	(16,330)
Inventories, prepaid expenses, and other current assets	(2,686)	1,662
Accounts payable and revenue and royalties payable	(674)	6,577
Accrued interest and other accrued liabilities	20,982	18,857
Net cash provided by operating activities	155,406	100,434
Cash flows from investing activities:		
Exploration and development of oil and natural gas properties	(167,758)	(130,672)
Property acquisitions	(8,529)	(2,413)
Capitalized interest	(5,190)	(10,392)
Proceeds from sale of assets	15,700	—
Deposits on asset sales	(3,300)	—
Net cash used in investing activities	(169,077)	(143,477)
Cash flows from financing activities:		
Proceeds from issuances on line of credit	—	124,100
Repayments of borrowings under line of credit	—	(115,900)
Proceeds from issuance of 6.375% Senior notes due 2022	600,000	—
Long-term borrowings under credit facility	102,700	63,500
Repayments of long-term borrowings under credit facility	(634,200)	(28,500)
Financing obligation	(101)	(92)
Debt issuance costs	(10,569)	(4)
Dividends paid	(4,381)	(4,060)
Stock options and restricted stock issued	3,498	1,573
Excess income tax benefit	422	2,228
Net cash provided by financing activities	57,369	42,845
Net increase (decrease) in cash and cash equivalents	43,698	(198)
Cash and cash equivalents at beginning of period	298	278
Cash and cash equivalents at end of period	$43,996	$80
Noncash investing activities:		
Accrued capital expenditures	$41,339	$28,623
Asset retirement obligation	4,994	917

The accompanying notes are an integral part of these Condensed Financial Statements.

BERRY PETROLEUM COMPANY

Condensed Statements 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, 2011	$521	$18	$350,158	$495,549	$ (5,517)	$840,729
Stock options and restricted stock issued	3	—	3,495	—	—	3,498
Stock based compensation expense	—	—	3,104	—	—	3,104
Income tax effect of stock option exercises	—	—	422	—	—	422
Dividends ($0.080 per share)	—	—	—	(4,381)	—	(4,381)
Net earnings	—	—	—	33,898	—	33,898

Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	1,267		1,267
Balances at March 31, 2012	$524	$18	$357,179	$525,066	$ (4,250	)	$878,537

The accompanying notes are an integral part of these Condensed Financial Statements.

2

Table of Contents

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 to prepare 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, 2011. The year-end Condensed Balance Sheet was derived from audited Financial Statements included in such report, but does not include all disclosures required by GAAP.

The Company's cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at March 31, 2012 and December 31, 2011 are $15.6 million and $16.1 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Recent Accounting Standards

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-11 which requires that an entity disclose both gross and net information about instruments and transactions that are either eligible for offset in the balance sheet or subject to an agreement similar to a master netting agreement, including derivative instruments. ASU 2011-11 was issued in order to facilitate comparison between GAAP and IFRS financial statements by requiring enhanced disclosures, but does not change existing GAAP that permits balance sheet offsetting. This authoritative guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The Company is currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on the Company's financial position or results of operations.

2. Acquisitions and Divestures

2012 Divestiture

On December 21, 2011, the Company entered into an agreement to sell its assets related to proved developed properties in Elko, Eureka and Nye Counties, Nevada (Nevada Assets), which closed on January 31, 2012, for total cash consideration of $15.6 million. The Company recorded a $1.7 million gain in conjunction with the sale. The gain was recorded in the Condensed Statements of Operations under the caption gain on sale of assets.

2011 Acquisition

On May 25, 2011, the Company acquired interests in producing properties on approximately 6,000 net acres in the Wolfberry trend in the Permian for an aggregate purchase price of $128.4 million. The acquisition was financed using the Company's credit facility.

3. Debt

Issuance and Sale of 6.375% Senior Notes Due 2022

On March 9, 2012, the Company issued $600 million aggregate principal amount of its 6.375% Senior Notes due 2022 (2022 Notes) for net proceeds of $589.5 million. Interest is payable in arrears semi-annually in March and September of each year, beginning September 2012. The 2022 Notes are senior unsecured obligations of the Company, which rank effectively junior to all of the Company's existing and any future secured debt, to the extent of the value of the collateral securing that debt, equally in right of payment with the Company's 10.25% Senior Notes due 2014 (2014 Notes) and 6.75% Senior Notes due 2020 (2020 Notes), and senior in right of payment to all of the Company's existing and any future subordinated debt.

On and after March 15, 2017, the Company may redeem all or, from time to time, a part of the 2022 Notes upon not less than 30 nor more than 60 days' notice, at the following redemption prices (expressed as a percentage of principal amount of notes to be redeemed), plus accrued and unpaid interest, if any, to the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the 12-month period beginning on March 15 of the years indicated below:

2017	103.188	%
2018	102.125	%
2019	101.063	%
2020 and thereafter	100.000	%

In addition, before March 15, 2015, the Company may, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net cash proceeds of certain equity offerings and if certain conditions are met as described in the indenture governing the 2022 Notes, at a redemption price of 106.375% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. At any time prior to March 15, 2017, the Company may also redeem all or part of the 2022 Notes at a redemption price equal to 100% of the principal amount of the Notes redeemed plus a "make-whole" premium described in the indenture, plus accrued and unpaid interest, if any, to the redemption date.

Pursuant to the terms of the credit facility, the issuance of the 2022 Notes automatically reduced the borrowing base of the credit facility by 25 cents per dollar of the 2022 Notes issued.

Tender Offer and Redemption of Notes

Concurrently with the offering of the 2022 Notes, the Company conducted a cash tender offer for up to $150.0 million aggregate principal amount of the Company's 2014 Notes, which expired on April 2, 2012. Pursuant to the terms of the credit facility, the repurchase of $150.0 million of 2014 Notes in the tender offer increased the borrowing base of the credit facility by 25 cents per dollar of the 2014 Notes repurchased.

Upon the closing of the offering of the 2022 Notes, the Company issued a notice to redeem all $200 million aggregate principal amount of the Company's 2016 Notes at a total redemption price of approximately $215.5 million, including accrued and unpaid interest. The redemption of the 2016 Notes was completed on April 9, 2012. Pursuant to the terms of the credit facility, the redemption of subordinated notes does not affect the borrowing base of the credit facility.

For additional discussion of the tender offer and redemption, see Note 11 to the Condensed Financial Statements.

Senior Secured Revolving Credit Facility

As of March 31, 2012, the Company's credit facility had a borrowing base of $1,287.5 million after giving effect to adjustments related to the Company's issuance of its 2022 Notes and the repurchase of its 2014 Notes in the tender offer. At March 31, 2012, lender commitments under the facility were $1.2 billion. On April 13, 2012, the Company entered into a fourth amendment to its credit facility, which increased the borrowing base to $1.4 billion. For additional discussion of the amendment, see Note 11 to the Condensed Financial Statements.

Borrowings under the credit facility bear interest at either (i) LIBOR plus a margin between 1.50% and 2.50% or (ii) the prime rate plus a margin between 0.50% and 1.50%, in each case, based on the amount utilized. The annual commitment fee on the unused portion of the credit facility ranges between 0.35% and 0.50% based on the amount utilized.
As of March 31, 2012, there were $23.2 million in outstanding letters of credit and no outstanding borrowings under the facility, leaving $1,176.8 million in borrowing capacity available under the credit facility. As of December 31, 2011, there were $531.5 million in outstanding borrowings under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of the Company's proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. The Company and the lenders each have a right to one additional redetermination each year.

4. Income Taxes

The effective income tax rate for the three months ended March 31, 2012 and 2011 was 37.8% and 40.1%, respectively. The Company's provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation and other permanent differences. Additionally, the effective income tax rate in the three months ended March 31, 2011 differs from the statutory rate due to a one-time reduction in deferred state income taxes as a result of acquisitions in more favorable jurisdictions, reducing future state income tax obligations. This benefit increased the effective income tax rate due to the Company's reporting a loss in the first quarter of 2011.

As of March 31, 2012, the Company had a gross liability for uncertain income tax benefits of $2.9 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 2012. Consistent with the Company's policy, interest and penalties on income taxes have been recorded as a component of the income tax provision (benefit). The Company estimates that it is reasonably possible that the balance of unrecognized income tax benefits as of March 31, 2012 could decrease by a maximum of $2.7 million in the next 12 months due to the expiration of statutes of limitation and audit settlements.

5. Earnings (Loss) Per Share

Basic net earnings (loss) per share is calculated by dividing net earnings (loss) available to common shareholders by the weighted average shares outstanding-basic during each period. Diluted earnings (loss) per share is calculated by dividing earnings (loss) available to common shareholders by the weighted average shares outstanding-dilutive, which includes the effect of potentially dilutive securities. Potentially dilutive securities consist of unvested restricted stock awards and outstanding stock options. No potential shares of common stock are included in the computation of any diluted per share amount when a net loss exists.

The two-class method of computing net earnings (loss) per share is required for those entities that have participating securities. The two-class method is an earnings allocation formula that determines net earnings (loss) per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Unvested restricted shares issued under the Company's equity incentive plans prior to January 1, 2010 has the right to receive non-forfeitable dividends, participating on an equal basis with common shares, and thus are classified as participating securities. Participating securities do not have a contractual obligation to share in the Company's losses. Therefore, in periods of net loss, no portion of the loss is allocated to participating securities. Unvested restricted shares issued subsequent to January 1, 2010 under the Company's equity incentive plans do 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 net earnings (loss) per share for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31,	
(in thousands, except per share data)	2012	2011
Net earnings (loss)	$33,898	$(52,497)
Less: net earnings allocable to participating securities	171	—
Net earnings (loss) available for common shareholders	$33,727	$(52,497)
Basic net earnings (loss) per share	$0.62	$(0.98)
Diluted net earnings (loss) per share	$0.61	$(0.98)
Weighted average shares outstanding—basic	54,759	53,866
Add: Dilutive effects of stock options and RSUs	504	—
Weighted average shares outstanding—dilutive	55,263	53,866

Options to purchase 0.3 million and 1.9 million shares were not included in the diluted earnings (loss) per share calculation for the three months ended and March 31, 2012 and March 31, 2011, respectively because their effect would have been anti-dilutive.

6. Asset Retirement Obligation

The following table summarizes the activity for the Company's asset retirement obligation (ARO) for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31,	
(in thousands)	2012	2011
Beginning balance at January 1	$64,019	$53,443
Liabilities incurred	2,993	917
Liabilities settled	(467)	(103)
Disposition of assets	(705)	—
Accretion expense	1,223	1,263
Revisions in estimated cash flows	2,001	—
Ending balance at March 31	$69,064	$55,520

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

7. Equity Incentive Compensation Plans

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

Total compensation cost recognized in the Condensed Statements of Operations for the grants under the Company's equity incentive compensation plans was $3.0 million and $2.9 million during the three months ended March 31, 2012 and 2011, respectively.

Stock Options

The following table summarizes stock option activity for the three months ended March 31, 2012:

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)(1)	Number of Shares Exercisable
Outstanding at January 1, 2012	1,520,689	$30.32	$17,798	1,434,020
Granted	82,262	53.02	—	—
Exercised	(197,209)	17.73	6,779	—
Cancelled/expired	—	—	—	—
Outstanding at March 31, 2012	1,405,742	$33.41	$20,317	1,257,883

(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 2012, 82,262 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 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 grant date fair value of each option granted was estimated using the Black-Scholes option pricing model. Expected volatility was calculated based on the historical volatility of the Company's common stock, and the risk-free interest rate was based on U.S. Treasury yield curve rates with maturities consistent with the expected life of each option. The key assumptions used in computing the weighted average fair market value of stock options granted were as follows:

	2012
Expected volatility	50.00 %
Risk-free interest rate	0.95 %
Dividend yield	0.57 %
Expected term (in years)	5.2

As of March 31, 2012, there was $3.2 million of total unrecognized compensation cost related to outstanding stock options. This cost is expected to be recognized over 4.0 years.

Restricted Stock Units

The following table summarizes restricted stock unit (RSU) activity for the three months ended March 31, 2012:

	RSUs	Weighted Average	Vest Date Fair

		Grant Date Fair Value	Value (in thousands)
Outstanding at January 1, 2012	915,022	$23.88	
Granted	143,601	52.08	
Issued	(49,706)	43.23	$2,406
Canceled/expired	(4,490)	25.13	
Outstanding at March 31, 2012(1)(2)	1,004,427	$26.74	

(1) The balance outstanding includes 43,554 RSUs granted to the non-employee Directors that are 100% vested at date of grant, but are subject to deferral elections delaying the date on which the corresponding shares are issued.

(2) The balance outstanding includes 469,165 RSUs granted to executive officers and other officers that have vested in accordance with the RSU agreement, but are subject to deferral elections delaying the date on which the corresponding shares are issued.

As of March 31, 2012, there was $15.5 million of total unrecognized compensation cost related to RSUs granted. This cost is expected to be recognized over 4.0 years.

Performance Share Program

The following table summarizes performance share award activity for the three months ended March 31, 2012:

	Performance Share Awards (1)	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at January 1, 2012	162,849	$39.00	
Granted	59,738	63.69	
Issued	—	—	$—
Canceled/expired	—	—	
Outstanding at March 31, 2012	222,587	$45.79	

(1) Reflects the maximum number of performance shares that can be issued.

In March 2012, 59,738 RSUs that are subject to performance metrics and a three-year service condition (performance shares) were granted to executive officers and certain other officers. The vesting of the performance share awards is contingent upon satisfying certain performance criteria. No performance shares will vest unless, from January 1, 2012 to December 31, 2014, the Company maintains an interest coverage ratio of at least 2.5 to 1.0, achieves a defined total shareholder return as compared to the Company's defined peer group and achieves a defined level of compounded annual production growth as measured by average annual barrels of oil equivalent per day (excluding acquisitions and divestitures). If such thresholds are met, the number of performance shares that vest is based on the excess total shareholder return and compounded annual production growth over the thresholds.

For the portion of the performance shares subject to a performance-based vesting condition based on the Company's annual production growth, the grant date fair value was determined by reference to the closing price of the Company's 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 the performance shares subject to a market performance-based vesting condition based on the Company's total shareholder return, the grant date fair value was estimated using a Monte Carlo simulation method. 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:

	2012	
Number of simulations	100,000	
Expected volatility	50	%
Risk-free interest rate	0.42	%

All compensation expense related to the market performance-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

As of March 31, 2012, there was $3.5 million of total unrecognized compensation cost related to performance share awards granted. This cost is expected to be recognized over 2.8 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 historically 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 March 31, 2012, the Company had commodity derivatives associated with the following volumes:

	2012	2013	2014
Oil Bbl/D:	21,000	15,000	4,000
Natural Gas MMBtu/D:	—	—	—

The Company entered into the following crude oil three-way collars during the three months ended March 31, 2012:

Term	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call
Full year 2014	1,000	$70.00 / $90.00 / $120.00
Full year 2014	1,000	$70.00 / $90.00 / $121.80

In March 2012, the Company terminated certain of its natural gas derivative instruments, which were associated with a total of 15,000 MMBtu/D for the remainder of 2012. The termination resulted in cash settlements of $14.7 million, offset by a non-cash fair value loss of $16.6 million. The net loss of $1.9 million is recorded in the Condensed Statements of Operations under the caption realized and unrealized loss on derivative, net.

BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
8. Derivative Instruments (Continued)

Discontinuance of Cash Flow Hedge Accounting

Effective January 1, 2010, the Company elected to de-designate all of its commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009. As a result, subsequent to December 31, 2009, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive loss (AOCL). As a result of discontinuing hedge accounting on January 1, 2010, the fair values of the Company's open derivative contracts designated as cash flow hedges as of December 31, 2009, less any ineffectiveness recognized, were frozen in AOCL and are reclassified into earnings as the original hedge transactions settle.

At December 31, 2011, AOCL consisted of $8.9 million ($5.5 million, net of income tax) of unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. At March 31, 2012, AOCL consisted of $6.9 million ($4.2 million net of income tax) of unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. During the three months ended March 31, 2012, $2.0 million ($1.3 million, net of income tax) 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 $4.2 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:

	March 31, 2012			
(in millions)	Derivative Assets Balance Sheet Classification	Fair Value	Derivative Liabilities Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	$0.3	Derivative liabilities	$44.7
Long term:				
Commodity	Derivative assets	0.3	Derivative liabilities	19.3
Total derivatives		$0.6		$64.0

	December 31, 2011			
(in millions)	Derivative Assets Balance Sheet Classification	Fair Value	Derivative Liabilities Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	$6.1	Derivative liabilities	$20.4
Long term:				
Commodity	Derivative assets	7.0	Derivative liabilities	15.5
Total derivatives		$13.1		$35.9

Table of Contents
BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
8. Derivative Instruments (Continued)

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

(in millions) Description of (Gain) Loss	Location of (Gain) Loss Recognized in Earnings	Three Months Ended March 31, 2012	2011
Commodity			
Loss reclassified from AOCL into earnings (amortization of frozen amounts)	Sales of oil and natural gas	$2.7	$14.6
Loss recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized loss on derivatives, net	28.5	127.5
Interest rate			
(Gain) loss reclassified from AOCL into earnings (amortization of frozen amounts)	Interest	$(0.6)	$0.8

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 March 31, 2012 was $0.5 million.

As of March 31, 2012, the counterparties to the Company's commodity derivative contracts consist of six financial institutions. The Company's counterparties or their affiliates are also lenders under the Company's credit facility. As a result, the counterparties to the Company's derivative agreements share in the collateral supporting the Company's credit facility. The Company is not generally required to post additional collateral under derivative agreements.

Certain of the Company's derivative agreements contain cross default provisions that require acceleration of amounts due under such agreements if the Company were to default on its obligations under its material debt agreements. In addition, if the Company were to default on certain of its material debt agreements, including, potentially, its derivative agreements, the Company would be in default under the credit facility. As of March 31, 2012, the Company was in a net liability position with five of the counterparties to the Company's derivative instruments, totaling $64.0 million. As of March 31, 2012, the Company's largest three counterparties accounted for 76% 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

Table of Contents
BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
9. Fair Value Measurements (Continued)

curves are obtained from independent pricing services, and the Company has made no adjustments to the obtained prices. The independent pricing services publish observable market information from multiple brokers and exchanges. All valuations were compared against counterparty valuations to verify the reasonableness of prices. The Company also considers counterparty credit risk and its own credit risk in its determination of all estimated fair values. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative contracts it holds. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

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 March 31, 2012 and December 31, 2011:

(in millions)	Total	Level 1	Level 2	Level 3
Commodity derivative liability, net				
March 31, 2012	$63.5	$—	$63.5	$—
December 31, 2011	$22.7	$—	$22.7	$—

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 March 31,	
(in millions)	2012	2011
Fair value liability, beginning of period	$—	$101.8
Transfers out of Level 3(1)	—	(101.8)
Realized and unrealized (gain) loss included in earnings	—	—
Settlements	—	—
Fair value liability, end of period	$—	$—
Total unrealized (gain) loss included in earnings related to financial assets and liabilities still on the Condensed Balance Sheets at March 30, 2012 and 2011	$—	$—

(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.

6

Table of Contents
BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
9. Fair Value Measurements (Continued)

Fair Market Value of Financial Instruments

The Company uses various assumptions and methods in estimating the fair values of its financial instruments. The following table presents fair value information about the Company's financial instruments:

March 31, 2012	Carrying Amount	Estimated Fair Value			
(in millions)		Level 1	Level 2	Level 3	Total
Cash and cash equivalents(1)	$44	$44	$—	$—	$44
Senior secured revolving credit facility(2)	—	—	—	—	—
8.25% Senior subordinated notes due 2016	200	209	—	—	209
10.25% Senior notes due 2014(3)	355	409	—	—	409
6.75% Senior notes due 2020	300	319	—	—	319
6.375% Senior notes due 2022	600	618	—	—	618
	$1,499	$1,599	$—	$—	$1,599

(1) Consists primarily of money market mutual funds.
(2) The Company's secured revolving credit facility can be repaid at any time without penalty. Interest is generally fixed for 30-day increments at the prime rate or LIBOR plus a stipulated margin for the amount utilized and at a stipulated percentage as a commitment fee for the portion not utilized. The Company uses a market approach to ensure the terms of its credit facility are in line with market rates for similar credit facilities, which are considered to be level 2 inputs.
(3) Carrying amount does not include unamortized discount of $6.0 million.

December 31, 2011

(in millions)	Carrying Amount	Estimated Fair Value
Senior secured revolving credit facility	532	532
8.25% Senior subordinated notes due 2016	200	209
10.25% Senior notes due 2014(1)	355	402
6.75% Senior notes due 2020	300	302
	$1,387	$1,445

(1) Carrying amount does not include unamortized discount of $6.6 million.

10. 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 crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. Gross operated oil production from the Company's Uinta properties averaged approximately 3,770 Bbl/D in the first three months of 2012. 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 2011 filed with the SEC on February 28, 2012.
E. Texas Gathering System

In July 2009, the Company closed on the financing of its E. Texas natural gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term natural gas gathering agreements for the E. Texas production which contained an embedded lease. The transaction was treated as a financing obligation. Accordingly, the $16.7 million net book value of the property is being depreciated over the remaining useful life of the asset and the cash received of $18.4 million was recorded as a financing obligation. A portion of the payments under the agreements are recorded as gathering 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 March 31, 2012 and 2011, the Company incurred $0.9 million and $1.7 million, respectively, under the agreements, which is recorded in the Condensed Financial Statements under the caption operating costs-oil and natural gas production.

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 and requires the Company to reassign to such co-owner, by January 31, 2020, all of the interest acquired by the Company from the co-owner in each 160-acre tract in which the Company has not drilled and completed a well that is producing or capable of producing from a designated formation, or deeper formation, on January 1, 2020. The amendment also requires the Company to pay the first $9.0 million of costs incurred in connection with the construction of either an extension of the existing access road or a new access road, including the third party's 50% share. If by June 30, 2013 (which date may be extended until December 31, 2014 if road construction has commenced by June 30, 2013), 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 million and the actual amount expended on road construction as of such date. Due to the need to obtain regulatory approvals, the Company has not yet commenced construction of either an extension of the existing access road or a new access road and may be unable to do so by June 30, 2013, thus triggering the payment obligation to the third party.

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 would 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 and paid $100,000 in July 2011. The Company expects to fund the mutually acceptable project during the first half of 2012.

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 agreements, as well as applicable law. However, the disputed amounts that the Company may be required to pay are up to approximately $7.1 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.

11. Subsequent Events

Credit Facility Amendment

On April 13, 2012, as part of the semi-annual borrowing base redetermination process, the Company entered into a fourth amendment to its credit facility. Among other things, the fourth amendment increased the borrowing base from $1,287.5 million to $1.4 billion. Total lender commitments remained unchanged at $1.2 billion.

Tender Offer and Redemption of Notes

On April 3, 2012, pursuant to the terms of the Offer to Purchase dated March 6, 2012, the Company repurchased $150.0 million aggregate principal amount of its 2014 Notes for an aggregate purchase price of $181.5 million, including accrued and unpaid interest. A related loss of $30.7 million will be recorded in the second quarter of 2012 consisting of $26.2 million for premiums paid over par and $4.5 million for write-offs of net discounts and debt issuance costs. The 2014 Notes were repurchased using net proceeds from the issuance of the Company's 2022 Notes. Following the closing of the tender offer on April 3, 2012, $205.3 million aggregate principal amount of 2014 Notes was outstanding.

On April 9, 2012, the Company redeemed all $200 million aggregate principal amount of its 2016 Notes for an aggregate purchase price of $215.5 million, including accrued and unpaid interest. A related loss of $10.6 million will be recorded in the second quarter of 2012 consisting of $8.3 million for premiums paid over par and $2.3 million for write-offs of debt issuance costs. The 2016 Notes were redeemed using net proceeds from the issuance of the Company's 2022 Notes.

For additional discussion of the tender offer and redemption, see Note 3 to the Condensed Financial Statements.

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, 2011, included in our Annual Report on Form 10-K and the Condensed Financial Statements included elsewhere herein.

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

Diatomite

In the first quarter of 2012, we began implementing a redesign of our development of our Diatomite assets. The redesign includes bringing a larger number of wells into production simultaneously, utilizing smaller injection cycles and monitoring real-time asset performance. Each of these changes was designed to minimize subsurface wellbore stress. We have drilled 90 gross (90 net) wells since the beginning of the fourth quarter of 2011, and have commenced steam injection in these wells. These changes impacted ongoing operations throughout the first quarter of 2012, as we had to temporarily take more producing wells off-line to accommodate the drilling and simultaneous start-up of our new wells. These wells have since returned to production, and this process is included in our plan going forward.

We received revisions to our project approval letter from the California Department of Oil and Gas and Geothermal Resources (DOGGR) in February 2012, which removed the requirement to cease cyclic steaming operations on wells located within 150 feet of a failed well bore until that well was either repaired or abandoned. Additionally, revisions in the administration of current regulations from DOGGR should reduce operational issues we had experienced. For example, shutting in production in proximity to a failed well bore exacerbated the stress on the surrounding wells and locally increased the incidence of additional failures. The requirement to shut in the surrounding wells reduced the number of completions that we were able to bring back online. We believe we have a sufficient set of active completions in our cyclic operations to increase our total Diatomite production in 2012, although we expect our 2012 Diatomite production to be approximately 400 BOE/D behind schedule as a result of these issues.

Notable First Quarter 2012 Items

- Generated discretionary cash flow of $131.5 million from production of 34,447 BOE/D, of which 73% was oil(1)
- Generated operating margin of $53.73 per BOE, supported by sales of our California heavy oil at a $7.63 average premium to WTI during the quarter(1)
-

Production from our North Midway-Sunset New Steam Floods properties, which include McKittrick, averaged 1,510 BOE/D, a 19% increase from the fourth quarter of 2011

- Acquired approximately 16,000 undeveloped net acres in the Permian for $6.9 million, bringing our total Permian position to 58,000 net acres
- Issued $600 million aggregate principal amount of our 6.375% senior notes due 2022 (2022 Notes) and used the proceeds to, among other things, reduce borrowings under our credit facility

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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.

Table of Contents

Notable Items and Expectations for the Second Quarter and Full Year 2012

- Used the proceeds from the issuance of the 2022 Notes to redeem all $200 million aggregate principal amount of our 8.25% senior subordinated notes due 2016 (2016 Notes) and $150.0 million aggregate principal amount of our 10.25% senior notes due 2014 (2014 Notes) in April 2012
- Completed our semi-annual credit facility redetermination and increased the borrowing base to $1.4 billion

Results of Operations.

In the first quarter of 2012, we reported net earnings of $33.9 million, or $0.61 per diluted share, and net cash flows from operations of $155.4 million. Net earnings in the first quarter of 2012 includes a $1.1 million gain associated with the sale of our Nevada Assets, $9.1 million in cash settlements received from the early termination of our natural gas derivatives and a loss on derivatives of $26.6 million resulting from non-cash changes in fair values and amortization of AOCL related to de-designated hedges, in each case net of income taxes.

Table of Contents

Operating Data.

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

	March 31, 2012	%	March 31, 2011	%	December 31, 2011	%
Heavy oil production (BOE/D)	17,005	49	16,226	47	17,497	49
Light oil production (BOE/D)	8,091	24	6,422	19	8,166	23
Total oil production (BOE/D)	25,096	73	22,648	66	25,663	72
Natural gas production (Mcf/D)	56,105	27	70,542	34	60,759	28
Total (BOE/D)(1)	34,447	100	34,405	100	35,790	100
Oil and natural gas, per BOE:						
Average realized sales price	$74.33		$60.26		$69.29	
Average sales price including cash derivative settlements	$74.44		$59.01		$68.80	
Oil, per BOE:						
Average WTI price	$103.03		$94.60		$94.06	
Price sensitive royalties(2)	(4.24)		(3.56)		(3.63)	
Quality differential and other(3)	(1.48)		(5.68)		4.75	
Oil derivatives non-cash amortization(4)	(1.14)		(7.07)		(6.76)	
Oil revenue	$96.17		$78.29		$88.42	
Add: Oil derivatives non-cash amortization(4)	1.14		7.07		6.76	
Oil derivative cash settlements(5)	(3.08)		(10.24)		(8.89)	
Average realized oil price	$94.23		$75.12		$86.29	
Natural gas price:						
Average Henry Hub price per MMBtu	$2.72		$4.11		$3.54	
Conversion to Mcf	0.18		0.21		0.21	
Natural gas derivatives non-cash amortization(4)	(0.01)		(0.01)		—	
Location, quality differentials and other	(0.30)		(0.09)		(0.24)	
Natural gas revenue per Mcf	$2.59		$4.22		$3.51	
Add: Natural gas derivatives non-cash amortization(4)	0.01		0.01		—	
Natural gas derivative cash settlements(5)	0.92		0.41		0.61	
Average realized natural gas price per Mcf	$3.52		$4.64		$4.12	

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

(2) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2012 base price of $17.43 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in the first quarter of 2012 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $17.78 in 2013.

(3) In California, the per barrel oil posting differential at March 31, 2012 was $10.27, ranged from $2.18 to $10.27 during the first quarter of 2012 and averaged $7.63 during the first quarter of 2012. In Utah, the per barrel oil posting differential at March 31, 2012 was ($16.00), ranged from ($12.49) to ($16.00) during the first quarter of 2012 and averaged ($14.93) during the first quarter of 2012.

(4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in the Condensed Statements of Operations under the caption sales of oil and natural gas.

(5) Cash settlements on derivatives, recorded in the Condensed Statements of Operations under the caption realized and unrealized loss on derivatives, net.

Table of Contents

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

	March 31, 2012	March 31, 2011	1Q11 to 1Q12 Change	December 31, 2011	4Q11 to 1Q12 Change
Sales of oil	$220,452	$160,624	37 %	$207,689	6 %
Sales of natural gas	13,201	26,765	(51)%	19,609	(33)%
Total sales of oil and natural gas	$233,653	$187,389	25 %	$227,298	3 %
Sales of electricity	5,980	6,412	(7)%	10,750	(44)%
Natural gas marketing	1,859	3,685	(50)%	2,550	(27)%
Gain on sale of assets	1,763	—	100 %	—	100 %
Interest and other income, net	747	128	484 %	390	92 %
Total revenues and other income	$244,002	$197,614	23 %	$240,988	1 %
Net earnings (loss)	$33,898	$(52,497)	—	$(414,733)	—
Diluted earnings (loss) per share	$0.61	$(0.98)	—	$(7.62)	—

Sales of Oil and Natural Gas.

Sales of oil and natural gas increased $46.3 million, or 25%, to $233.7 million in the first quarter of 2012 compared to $187.4 million in the first quarter of 2011. The increase was primarily due to a 23% increase in the average realized sales price in the first quarter of 2012 compared to the first quarter of 2011 in part because oil production as a percentage of total production increased from 66% during the first quarter of 2011 to 73% in the first quarter of 2012. Sales of oil and natural gas increased $6.4 million, or 3%, to $233.7 million in the first quarter of 2012 compared to $227.3 million in the fourth quarter of 2011. The increase was primarily due to a 7% increase in the average realized sales price in the first quarter of 2012 compared the fourth quarter of 2011. Sales of oil and natural gas for the first quarter of 2012 were decreased by non-cash amortization of AOCL related to discontinuing hedge accounting of $2.7 million, or $0.86 per BOE, compared to $14.6 million, or $4.68 per BOE, in the first quarter of 2011 and $15.9 million, or $4.84 per BOE, in the fourth quarter of 2011.

Sales of Electricity.

The following table sets forth selected results of operations for the periods ended:

	Three Months Ended		
	March 31, 2012	March 31, 2011	December 31, 2011
Electricity			
Sales of electricity (in thousands)	$5,980	$6,412	$10,750
Operating costs (in thousands)	$5,017	$6,113	$5,720
Electric power produced—MWh/D	2,089	1,856	1,932
Electric power sold—MWh/D	1,935	1,689	1,774
Average sales price/MWh	$33.96	$42.17	$40.68
Fuel gas cost/MMBtu (including transportation)	$2.71	$4.33	$3.55
Fuel gas purchased (MMBtu/D)	27,000	23,000	25,000

Sales of electricity in the first quarter of 2012 decreased compared to the first quarter of 2011 due to a 19% decrease in the average sales price, partially offset by a 15% increase in electric power sold. Electricity operating costs in the first quarter of 2012 decreased compared to the first quarter of 2011 due to a 37% decrease in fuel gas cost, partially offset by a 17% increase in fuel gas volumes purchased. Sales of electricity decreased in the first quarter of 2012 compared to the fourth quarter of 2011 primarily due to a refund of $4.1 million associated with a retroactive payment adjustment for capacity that we received from one of our electricity customers in the fourth quarter of 2011. Additionally, the average sales price of electricity decreased 17%, partially offset by a 9% increase in electric power sold in the first quarter of 2012

Table of Contents

as compared to the fourth quarter of 2011. Electricity operating costs in the first quarter of 2012 decreased compared to the fourth quarter of 2011 primarily due to a 24% decrease in fuel gas cost, partially offset by an 8% decrease in fuel gas volumes purchased.

Electricity Sales Contracts. We sell electricity produced by our cogeneration (also referred to as Combined Heat and Power or CHP) facilities under long-term contracts approved by the California Public Utilities Commission (CPUC) to two California investor owned utilities (IOUs): Southern California Edison Company (Edison) and Pacific Gas and Electric Company (PG&E). These contracts are referred to as standard offer (SO) power purchase agreement (PPA) contracts, under which we are paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) of energy plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. Beginning in 2015, the energy prices we will be paid will be based on market prices for electricity.

At March 31, 2012, we sold energy and capacity from all Cogen units under interim extensions of legacy PPAs. The PPA for our Cogen 38 facility expired on March 31, 2012, at which time a transition PPA with PG&E became effective. Our current legacy extension PPAs for our Cogen 42 facilities were recently extended and are now scheduled to terminate on or about May 22, 2012, at which time we intend to enter into a transition PPA for the combined output of the two units. Transition PPAs are intended to be bridge agreements to allow qualifying cogeneration facilities, such as our cogeneration facilities, to bid against other Combined Heat and Power (CHP) facilities for long-term contracts with the IOUs and are similar to our current SO contracts, but with updated regulatory requirements and more stringent scheduling and performance requirements. Transition PPAs are to terminate no later than June 30, 2015, but may be terminated earlier in the event we elect to bid into a competitive CHP solicitation and are awarded a long-term contract based on our bid. Our Cogen facilities are eligible to bid into one or more of the competitive CHP solicitations that are expected to be issued over the next two to three years. For existing facilities, such as ours, the maximum term of a PPA awarded in a competitive CHP solicitation is seven years.

Our current legacy extension PPA with PG&E for our Cogen 18 facility was recently extended and is now scheduled to terminate on the earlier of September 30, 2012 or the date the CPUC approves a new Public Utility Regulatory Policy Act (PURPA) PPA for a term of seven years. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it will continue to be eligible for a PURPA PPA, under which it will be paid the prevailing CPUC-determined SRAC price and either a firm or as-available capacity payment, at our discretion.

The following table summarizes our cogeneration facilities and related contract information as of March 31, 2012:

Facility	Type of Contract(1)	Purchaser	Contract Expiration
Cogen 42 Unit 1	SO2	Edison	May 2012(2)
Cogen 42 Unit 2	SO1	Edison	May 2012(2)
Cogen 18	SO2	PG&E	Sept 2012(3)
Cogen 38	Transition	PG&E	Jun 2015

(1) SO1 contracts pay only "as available" capacity rates and SO2 contracts pay firm capacity rates.
(2) We anticipate the current contract will be replaced by a transition contract expiring June 30, 2015.
(3) We anticipate the current contract will be replaced by a PURPA contract with a term of up to seven years.

Natural Gas Marketing.

We have long-term firm transportation contracts on the Rockies Express, Wyoming Interstate Company (WIC), and Ruby pipelines, each with a total average capacity of 35,000 MMBtu/D. Demand charges for our capacity are reflected in operating costs-oil and natural gas production in our Condensed Statements of Operations. Our current production is insufficient to fully utilize this capacity. To optimize our remaining capacity, we purchase third-party natural gas at the market rate in our producing areas utilizing FERC-approved asset management agreements. Sales and purchases of third-party natural gas are recorded under natural gas marketing in the revenues and expenses sections of the Condensed Statements of Operations, respectively. The pre-tax net earnings of natural gas marketing operations for the three months ended March 31, 2012 and 2011 was $0.1 million and $0.2 million, respectively.

Table of Contents

Gain on Sale of Assets.

For the three months ended March 31, 2012, we recorded a $1.7 million gain in conjunction with the sale of assets related to proved developed properties in Elko, Eureka and Nye Counties, Nevada (Nevada Assets). The gain was recorded in the Condensed Statements of Operations under the caption gain on sale of assets.

Oil and Natural Gas Operating and Other Expenses.

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

	Amount Per BOE			Amount (in thousands)		
	March 31, 2012	March 31, 2011	December 31, 2011	March 31, 2012	March 31, 2011	December 31, 2011
Operating costs—oil and natural gas production	$17.31	$18.44	$18.11	$54,252	$57,083	$59,634
Production taxes	3.40	2.39	2.64	10,658	7,391	8,691
DD&A—oil and natural gas production	15.30	16.83	16.77	47,956	52,109	55,202
General and administrative	5.66	5.26	4.44	17,741	16,291	14,604
Interest expense	6.41	5.06	5.93	20,104	15,655	19,512
Total	$48.08	$47.98	$47.89	$150,711	$148,529	$157,643

- Operating costs—oil and natural gas production in the first quarter of 2012 were $54.3 million, or $17.31 per BOE, compared to $57.1 million, or $18.44 per BOE, in the first quarter of 2011 and $59.6 million, or $18.11 per BOE, in the fourth quarter of 2011. The decrease in operating costs—oil and natural gas production in the first quarter of 2012 compared to the first quarter of 2011 was primarily due to decreased costs of fuel used to produce steam. Compression, gathering, and dehydration costs also decreased over the same period primarily due to natural production decline from our natural gas assets, offset by increases in transportation costs primarily due to the commencement of Ruby Pipeline operations in July 2011, and increased field personnel costs due to increased development activities. The decrease in operating costs—oil and natural gas production in the first quarter of 2012 compared to the fourth quarter of 2011 was primarily due to decreased costs of fuel used to produce steam. Also decreasing over the same period were well servicing and maintenance and contract labor costs, primarily due to fewer well repairs in California, and compression, gathering, and dehydration costs due in part to natural production decline from our natural gas assets. 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 injection for the three months ended:

	March 31, 2012	March 31, 2011	1Q11 to 1Q12 Change		December 31, 2011	4Q11 to 1Q12 Change	
Average volume of steam injected (Bbl/D)	134,510	120,612	12	%	130,013	3	%
Fuel gas cost/MMBtu (including transportation)	$2.71	$4.33	(37	)%	$3.55	(24	)%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	45,591	39,552	15	%	43,939	4	%

Included in operating costs are firm transportation costs, which totaled $7.0 million and $4.0 million for the three months ended March 31, 2012 and 2011, respectively.

- Production taxes in the first quarter of 2012 were $10.7 million, or $3.40 per BOE, compared to $7.4 million, or $2.39 per BOE, in the first quarter of 2011 and $8.7 million, or $2.64 per BOE, in the fourth 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 first quarter of 2012 compared to the first quarter of 2011 was due to increases in oil prices, an increase in the assessed ad valorem values attributable to our California properties, increased ad valorem and

Table of Contents

production taxes related to new wells drilled in the Permian during 2011 and the expiration of certain tax exemptions in Utah. The increase in production taxes in the first quarter of 2012 compared to the fourth quarter of 2011 was due to increases in oil prices and increased ad valorem and production taxes related to new wells drilled in the Permian during 2011.

- Depreciation, depletion and amortization—oil and natural gas production (DD&A—oil and natural gas production) related to oil and natural gas production in the first quarter of 2012 was $48.0 million, or $15.30 per BOE, compared to $52.1 million, or $16.83 per BOE, in the first quarter of 2011 and $55.2 million, or $16.77 per BOE, in the fourth quarter of 2011. The decrease in DD&A—oil and natural gas production in the first quarter of 2012 compared to the first quarter of 2011 and the fourth quarter of 2011 was primarily due to the impairment of our East Texas natural gas assets in the fourth quarter of 2011, offset by the development of our properties with higher drilling and leasehold acquisition costs.

- General and administrative expense (G&A) in the first quarter of 2012 was $17.7 million, or $5.66 per BOE, compared to $16.3 million, or $5.26 per BOE, in the first quarter of 2011 and $14.6 million, or $4.44 per BOE, in the fourth quarter of 2011. The increase in G&A in the first quarter of 2012 compared to the first quarter of 2011 was primarily due to general increases in salaries and benefits, including bonus costs, resulting from personnel hired during the past twelve months, as well as general pay increases. The increase in G&A in the first quarter of 2012 compared to the fourth quarter of 2011 was primarily due to director compensation of $1.1 million recorded in the first quarter of 2012 and lower short-term incentive compensation costs in the fourth quarter of 2011 as a result of our 2011 annual performance.

- Interest expense in the first quarter of 2012 was $20.1 million, or $6.41 per BOE, compared to $15.7 million, or $5.06 per BOE, in the first quarter of 2011 and $19.5 million, or $5.93 per BOE, in the fourth quarter of 2011. The increase in interest expense in the first quarter of 2012 compared to the first quarter of 2011 was primarily due to a decrease in capitalized interest. The increase in interest expense in the first quarter of 2012 compared to the fourth quarter of 2011 was due to the issuance of $600 million aggregate principal amount of our 6.375% Senior Notes due 2022 Notes in March 2012, partially offset by a decrease in interest on our credit facility as a result of a decrease in outstanding borrowings.

Dry Hole, Abandonment, Impairment and Exploration. For the three months ended March 31, 2012, we incurred dry hole, abandonment, impairment and exploration expense of $3.0 million, primarily for the purchase of seismic data and plugging and abandonment. For the three months ended March 31, 2011, we incurred dry hole, abandonment, impairment and exploration expense of $0.1 million.

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

Table of Contents

Realized and Unrealized Loss on Derivatives, Net. The following table sets forth the derivative cash settlements and non-cash derivative contract fair value gains and losses recorded in the Condensed Statements of Operations under the caption realized and unrealized loss on derivatives, net for the periods indicated. See Notes 8 and 9 to the Condensed Financial Statements for more information on our derivative instruments.

(in thousands)	Three Months Ended March 31, 2012	March 31, 2011	December 31, 2011
Cash payments (receipts):			
Commodity derivatives—oil	$7,069	$21,009	$20,892
Commodity derivatives—natural gas(1)	(19,381)	(2,592)	(3,404)
Total cash (receipts) payments	$(12,312)	$18,417	$17,488
Mark-to-market loss (gain):			
Commodity derivatives—oil	$24,363	$107,089	$97,320
Commodity derivatives—natural gas(1)	16,430	2,010	(2,279)
Total mark-to-market loss	$40,793	$109,099	$95,041
Total realized and unrealized loss on derivatives, net	$28,481	$127,516	$112,529

(1) In March 2012, we terminated certain of our natural gas derivative instruments, which were associated with a total of 15,000 MMBtu/D for the remainder of 2012. The termination resulted in cash settlements of $14.7 million, offset by a non-cash fair value loss of $16.6 million. The net loss of $1.9 million is recorded in the Condensed Statements of Operations under the caption realized and unrealized loss on derivative, net.

Income Tax Expense. The effective income tax rate for the three months ended March 31, 2012 and 2011 was 37.8% and 40.1%, respectively. Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation and other permanent differences. Additionally, the effective income tax rate in the three months ended March 31, 2011 differs from the statutory rate due to a one-time reduction in deferred state income taxes as a result of acquisitions in more favorable jurisdictions, reducing future state income tax obligations. This benefit increased the effective income tax rate due to us reporting a loss in the first quarter of 2011.

Drilling Activity.

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

Asset Team	Three Months Ended March 31, 2012 Gross Production Wells		Net Production Wells
SMWSS—Steam Floods	8		8
NMWSS—Diatomite	72		72
NMWSS—New Steam Floods	12		12
Permian	21	(1)	15
Uinta	15		12
E. Texas	—		—
Piceance	—		—
Totals	128		119

(1) Includes six non-operated wells in which we have an average interest of approximately 0.55% each, or approximately 0.04 total net wells, and 15 gross operated wells.

Table of Contents

Properties.

We currently have seven asset teams, as follows: South Midway-Sunset (SMWSS)—Steam Floods, North Midway-Sunset (NMWSS)—Diatomite, NMWSS—New Steam Floods, 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 first quarter of 2012, we expanded the steam flood at our Homebase and Formax properties, drilling 8 gross (8 net) horizontal wells, which are all currently producing within expectations. For the remainder of 2012, we plan to continue development of the steam flood at our Ethel D property, adding additional steam generation capacity and drilling approximately 40 producing wells and five steam injection wells. In the second and third quarter of 2012, we plan to expand the steam flood at Poso Creek by drilling approximately 10 producing wells and six steam injection wells. Additionally, we plan to drill five producing wells and continue our recompletion program in the Upper Kraft zone at Placerita. Average daily production in the first quarter of 2012 from all of our SMWSS—Steam Floods assets was approximately 12,810 BOE/D compared to 13,235 BOE/D in the fourth quarter of 2011.

NMWSS—Diatomite. Our NMWSS—Diatomite asset team includes our Diatomite properties in the San Joaquin Valley. In the first quarter of 2012, we began implementing a redesign of our development of our Diatomite assets. The redesign includes bringing a larger number of wells into production simultaneously, utilizing smaller injection cycles, and monitoring real-time asset performance. Each of these changes was designed to minimize subsurface wellbore stress. We have drilled 90 gross (90 net) wells since the beginning of the fourth quarter of 2012, and have commenced steam injection in these wells. These changes impacted ongoing operations throughout the first quarter of 2012 as we had to temporarily take more producing wells off-line to accommodate the drilling and simultaneous start-up of our new wells. These wells have since returned to production, and this process is included in our plans going forward. Our focus in the second quarter will be on initiating steam injection into these wells. In addition, we plan to drill nine replacement wells by the end of the second quarter. Average daily production from our NMWSS—Diatomite assets in the first quarter of 2012 was approximately 2,685 BOE/D compared to 3,000 BOE/D in the fourth quarter of 2011.

NMWSS—New Steam Floods. Our NWMSS—New Steam Floods asset team includes our non-Diatomite North Midway-Sunset assets, including McKittrick, that were previously included in our NMWSS-Diatomite asset team, as well as our Main Camp, Fairfield, Pan, and USL-12 properties. Due to recent success of these NMWSS—New Steam Floods assets, we created a new asset team for these properties. In the first quarter of 2012, we drilled 11 gross (11 net) productive wells at our Main Camp property and one gross (one net) well at our Pan property. We also successfully completed our first steam cycle on 13 of the 42 new producers drilled in the last half of 2011 at our McKittrick property. In the second quarter of 2012, we plan to begin initial steam cycles on the remaining 29 wells at McKittrick and to drill an additional 40 wells across all of our NMWSS—New Steam Floods properties. Average daily production from all of our NMWSS—New Steam Floods assets in the first quarter of 2012 was approximately 1,510 BOE/D, a 19% increase from 1,270 BOE/D in the fourth quarter of 2011.

Permian. During the first quarter of 2012, our Permian drilling program averaged five rigs and we drilled 15 gross (15 net) wells and completed 13 wells. We entered 2012 with approximately 800 BOE/D of production shut-in due to gas curtailment. We completed work during the quarter to install secondary outlets in our key operating areas, which should reduce curtailments going forward. We continued to build our inventory of prospective acreage during the quarter and acquired approximately 16,000 net acres, bringing our total Permian acreage to approximately 58,000 net acres. We plan to continue to run approximately five rigs and drill 75 additional gross wells during the remainder of 2012. Additionally, we plan to drill four wells on our prospective acreage outside the Wolfberry fairway and evaluate those results during 2012. Average daily production in the first quarter of 2012 from our Permian assets was approximately 5,600 BOE/D, consistent with 5,605 BOE/D in the fourth quarter of 2011.

Uinta. During the first quarter of 2012, we drilled 15 gross (12 net) wells at our Uinta properties utilizing a three rig drilling program. All wells drilled targeted higher oil potential areas, with seven wells drilled in Brundage Canyon and eight in Lake Canyon. The Brundage Canyon wells included four Green River wells, two Green River/Wasatch commingled wells and one Uteland Butte horizontal well. All eight Lake Canyon wells were Green River/Wasatch commingled wells. Testing continues at our initial waterflood pilot in Brundage Canyon, and implementation of the second waterflood pilot is progressing, with three 20-acre infill wells inside the second pilot drilled in the first quarter. Average daily production from our Uinta assets was approximately 5,430 BOE/D in the first quarter of 2012 compared to 5,500 BOE/D in the fourth quarter of 2011.

E. Texas. We have deferred drilling in E. Texas in 2012 while we focus on higher return oil development opportunities at our other properties. Average daily production in the first quarter of 2012 from the E. Texas assets was approximately 18 MMcf/D compared to 20 MMcf/D in the fourth quarter of 2011.

Table of Contents

Piceance. We have deferred drilling in the Piceance in 2012 while we focus on higher return oil development opportunities at our other properties. Average daily production in the first quarter of 2012 from the Piceance assets was approximately 20 MMcf/D compared to 23 MMcf/D in the fourth quarter of 2011.

Financial Condition, Liquidity and Capital Resources.

Our development, exploitation, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and borrowings under our credit facility as our primary sources of liquidity. We have also used the debt and equity markets as other sources of financing to fund large acquisitions and other transactions and, as market conditions have permitted, we have engaged in asset monetization transactions. 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 March 31, 2012, we had a working capital deficit of approximately $46.0 million. We generally maintain a working capital deficit because we use excess cash to reduce borrowings under our credit facility. Our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

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 March 31, 2012, we had approximately 70% and 40% of our expected 2012 and 2013 oil production, respectively, hedged with 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 2012 and 2013. In the future, we may increase or decrease our derivative positions. Our derivatives counterparties are commercial banks that are parties to our credit facility or affiliates of those banks. See Item 3. Quantitative and Qualitative Disclosures About Market Risk below and Notes 8 and 9 to the Condensed Financial Statements for further details about our derivative instruments.

Senior Secured Revolving Credit Facility. At March 31, 2012, our senior secured revolving credit facility, which matures in May 2016, had a borrowing base of $1,287.5 million after adjustments related to our issuance of $600 million of our 2022 Notes and the repurchase of $150.0 million aggregate principal amount of our 2014 Notes pursuant to a cash tender offer. At March 31, 2012, lender commitments under the facility remained unchanged at $1.2 billion. On April 13, 2012, we entered into a fourth amendment to our credit facility, which increased the borrowing base to $1.4 billion. Lender commitments remained unchanged at $1.2 billion. For additional discussion of the amendment, see Note 11 to the Condensed Financial Statements.

Borrowings under the credit facility bear interest at either (i) LIBOR plus a margin between 1.50% and 2.50% or (ii) the prime rate plus a margin between 0.50% and 1.50%, in each case, based on the amount utilized. The annual commitment fee on the unused portion of the credit facility ranges between 0.35% and 0.50% based on the amount utilized.

As of March 31, 2012, there were $23.2 million in outstanding letters of credit and no outstanding borrowings under the facility, leaving $1,176.8 million in borrowing capacity available under the credit facility. As of December 31, 2011, there were $531.5 million in outstanding borrowings under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of our proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. We and the lenders each have a right to one additional redetermination each year.

The credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. The credit facility also contains other customary covenants, subject to certain agreed exceptions, including covenants restricting our ability to, among other things, owe or be liable for indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of the our material assets or properties; declare dividends on or redeem or repurchase our capital stock; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; engage in transactions with affiliates; and enter into, create or allow to exist contractual obligations limiting our ability to grant liens on our assets to the lenders under the credit facility. As of March 31, 2012, we were in compliance with all financial covenants and have complied with all financial covenants for all prior periods presented.

Table of Contents

Issuance and Sale of 6.375% Senior Notes Due 2022. On March 9, 2012, we issued $600 million aggregate principal amount of our 2022 Notes for net proceeds of $589.5 million. Interest is payable in arrears semi-annually in March and September of each year, beginning September 2012. The 2022 Notes are senior unsecured obligations, which rank effectively junior to all of our existing and any future secured debt, to the extent of the value of the collateral securing that debt, rank equally in right of payment with our 2014 Notes and our 6.75% Senior Notes due 2020 (2020 Notes), and senior in right of payment to all of our existing and any future subordinated debt.

On and after March 15, 2017, we may redeem all or, from time to time, a part of the 2022 Notes upon not less than 30 nor more than 60 days' notice, at the following redemption prices (expressed as a percentage of principal amount of notes to be redeemed), plus accrued and unpaid interest, if any, to the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the 12-month period beginning on March 15 of the years indicated below:

2017	103.188	%
2018	102.125	%
2019	101.063	%
2020 and thereafter	100.000	%

In addition, before March 15, 2015, we may, at our option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net cash proceeds of certain equity offerings and if certain conditions are met as described in the indenture governing the 2022 Notes, at a redemption price of 106.375% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. At any time prior to March 15, 2017, we may also redeem all or part of the 2022 Notes at a redemption price equal to 100% of the principal amount of the notes redeemed plus a “make-whole” premium described in the indenture governing the 2022 Notes, plus accrued and unpaid interest, if any, to the redemption date.

Tender Offer and Redemption of Notes. Concurrently with the offering of the 2022 Notes, we conducted a cash tender offer for up to $150.0 million aggregate principal amount of our 2014 Notes, which expired on April 2, 2012. Following the closing of the tender offer on April 3, 2012, $205.3 million aggregate principal amount of 2014 Notes was outstanding.

Upon the closing of the offering of the 2022 Notes, we issued a notice to redeem all $200 million aggregate principal amount of our 2016 Notes at a total redemption price of approximately $215.5 million, including accrued and unpaid interest. The redemption of the 2016 Notes was completed on April 9, 2012.

For additional discussion of the tender offer and redemption, see Notes 3 and 11 to the Condensed Financial Statements.

We may also seek, from time to time, to repurchase our outstanding debt through open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts repurchased may be material.

Outstanding Long-Term Indebtedness. As of April 19, 2012, following the closing of the tender offer for $150.0 million aggregate principal amount of our 2014 Notes and the redemption of all of our 2016 Notes, we had the following senior notes outstanding:

- $205.3 million aggregate principal amount of our 2014 Notes;

- $300 million aggregate principal amount of our 2020 Notes; and

- $600 million aggregate principal amount of our 2022 Notes.

The indentures governing our senior notes contain provisions that limit our ability to incur, assume or guarantee additional indebtedness; issue redeemable stock and preferred stock; pay dividends or distributions or redeem or repurchase capital stock; prepay, redeem or repurchase debt that is junior in right of payment to our senior and subordinated notes; make loans and other types of investments; incur liens; restrict dividends, loans or asset transfers from our subsidiaries; sell or otherwise dispose of assets, including capital stock of subsidiaries; consolidate or merge with or into, or sell substantially all of our assets to, another person; enter into transactions with affiliates; and enter into new lines of business. Upon specified change in control events, we will be required to make offers to repurchase our senior notes at amounts specified in the indentures governing such notes.

Table of Contents

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 contractual rights or obligations affected by our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our current 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 $55.0 million in the first three months of 2012 compared to the first three months of 2011 is primarily due to increased oil production and an increase in the average realized sales price.

Investing Activities. Net cash used in investing activities is primarily comprised of acquisition, exploration and development of oil and natural gas properties net of dispositions of oil and natural gas properties. The increase of $25.6 million in net cash used in investing activities in the first three months of 2012 compared to the first three months of 2011 is primarily due to increased development and acquisition activity partially offset by proceeds from the sale of our Nevada assets.

Financing Activities. Net cash provided by financing activities in the first three months of 2012 included net proceeds of $589.5 million from the issuance of $600 million aggregate principal amount of our 2022 Notes, offset by net repayments of $531.5 million of borrowings under our credit facility. Net cash provided by financing activities in the first three months of 2011 included net borrowings under our credit facility and money market line of credit of $43.2 million.

Capital Expenditures.

We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. For 2012, we are expecting full-year development capital of between $600 million and $650 million.

We believe that our cash flow provided by operating activities and funds available under our credit facility will be sufficient to fund our operating and capital expenditures budget and our short-term contractual operations for the remainder of 2012. 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 substantially 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.

Regulatory Matters.

On April 17, 2012, the Environmental Protection Agency (EPA) issued final rules that subject all oil and natural gas operations (production, processing, transmission, and storage) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce VOC emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells as well as existing wells that are refractured. Further, the finalized regulations under NESHAPS include emissions limitations for certain glycol dehydrators and storage vessels at major sources of hazardous air pollutants. We are currently evaluating the effect these rules will have on our business.

Recent Accounting Standards and Updates.

For further information on the potential effects of new accounting pronouncements see Note 1 to the Condensed Financial Statements.

Table of Contents

Reconciliation of Non-GAAP Measures.

Discretionary Cash Flow. Discretionary cash flow is a non-GAAP liquidity measure. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items and cash settlements from the early termination of natural gas derivatives. 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 discretionary cash flow to cash provided by operating activities, the most directly comparable GAAP measure, for the periods presented:

(in thousands)	Three Months Ended March 31, 2012
Net cash provided by operating activities	$155,406
Net increase in current assets	10,521
Net increase in current liabilities, including book overdraft	(19,799)
Cash settlements from early termination of natural gas derivatives	(14,659)
Discretionary cash flow	$131,469

Operating Margin per BOE. Operating margin per barrel consists of oil and natural gas revenues less oil and natural gas operating expenses and production taxes divided by the total BOEs sold during the period. Management uses operating margin per barrel as a measure of profitability and believes it provides useful information to investors because it relates our oil and natural gas revenue and oil and natural gas operating expenses to our total units of production providing a gross margin per unit of production, allowing investors to evaluate how our profitability varies on a per unit basis each period.

(per BOE)	Three Months Ended March 31, 2012
Average sales price including cash derivative settlements	$74.44
Average operating costs—oil and natural gas production	17.31
Average production taxes	3.40
Average operating margin	$53.73

Table of Contents

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 natural 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 natural gas price. 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 March 31, 2012, we have approximately 70% and 40% of our expected 2012 and 2013 oil production, respectively, hedged with 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 derivative instruments at March 31, 2012 would decrease the respective fair value of crude oil and natural gas derivative instruments at March 31, 2012 by \$91.9 million and \$0.1 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 derivative instruments at March 31, 2012 would increase the respective fair value of crude oil and natural gas derivative instruments at March 31, 2012 by \$78.0 million and \$0.1 million, respectively.

Table of Contents

The following table summarizes our commodity derivative position as of March 31, 2012:

Term	Average Barrels Per Day	Average Prices	Term	Average Barrels/MMBtu Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Three-Way Collars			Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2012	1,000	$65.00/$85.00/$97.25	Full year 2013	1,000	$70.00/$88.15/$100.00
Full year 2012	1,000	$70.00/$87.00/$105.00	Full year 2013	1,000	$70.00/$86.85/$100.00
Full year 2012	1,000	$70.00/$88.00/$106.00	Full year 2013	1,000	$69.70/$85.00/$100.00
Full year 2012	1,000	$60.00/$80.00/$96.92	Full year 2013	1,000	$70.00/$87.00/$108.50
Full year 2012	1,000	$60.00/$80.00/$120.00	Full year 2013	1,000	$70.00/$90.00/$116.50
Full year 2012	1,000	$70.00/$88.15/$100.00	Full year 2013	1,000	$70.00/$90.00/$120.00
Full year 2012	1,000	$70.00/$86.85/$100.00	Full year 2013	1,000	$70.00/$95.00/$120.10
Full year 2012	1,000	$69.70/$85.00/$100.00	Full year 2013	1,000	$77.95/$105.00/$115.00
Full year 2012	1,000	$70.00/$87.00/$108.50	Full year 2013	1,000	$80.00/$107.00/$119.60
Full year 2012	1,000	$70.00/$90.00/$116.50	Full year 2013	500	$70.00/$90.00/$100.00
Full year 2012	1,000	$70.00/$90.00/$120.00	Full year 2013	500	$70.00/$90.00/$100.00
Full year 2012	1,000	$70.00/$95.00/$120.10	Full year 2013	1,000	$75.00/$90.00/$101.85
Full Year 2012	1,000	$77.95/$105.00/$115.00	Full year 2014	1,000	$77.95/$105.00/$115.00
Full Year 2012	1,000	$80.00/$107.00/$119.60	Full year 2014	1,000	$80.00/$107.00/$119.60
Full year 2012	500	$70.00/$90.00/$100.00	Full year 2014	1,000	$70.00/$90.00/$120.00
Full year 2012	500	$70.00/$90.00/$100.00	Full year 2014	1,000	$70.00/$90.00/$121.80
Full year 2012	1,000	$75.00/$90.00/$101.85			
Full year 2012	1,000	$70.00/$85.00/$92.00	Natural Gas Sales (NYMEX HH to NGPL-Tex OK)		
Full year 2012	2,000	$70.00/$80.00/$83.00	Basis Swaps		
Full year 2012	1,500	$75.00/$90.00/$97.50	Full year 2012	2,500	$0.44
Full year 2012	500	$75.00/$90.00/$106.90			
Full year 2013	1,000	$65.00/$85.00/$97.25	Natural Gas Sales (NYMEX HH TO HSC)		
Full year 2013	1,000	$70.00/$87.00/$105.00	Basis Swaps		
Full year 2013	1,000	$70.00/$88.00/$106.00	Full year 2012	2,500	$0.32
Full year 2013	1,000	$60.00/$80.00/$103.30			

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 $0.075 to $0.08 during 2012 and $0.07 to $0.075 during 2013.

Interest rate risk

Our credit facility 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 facility 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 March 31, 2012, we had no outstanding borrowings under our credit facility.

Table of Contents

Item 4. Controls and Procedures

As of March 31, 2012, 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 March 31, 2012, 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 Securities and Exchange Commission (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 controls over financial reporting that occurred during the three months ended March 31, 2012 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, 2011, filed with the SEC on February 28, 2012, under the heading "Risk Factors".

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information set forth under "Legal Matters" in Note 10 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, 2011 filed with the SEC on February 28, 2012.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosure

Not applicable.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

Exhibit No.	Description of Exhibit
4.1	Fourth Amendment to the Second Amended and Restated Credit Agreement dated April 13, 2012 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 17, 2012, 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**	Interactive data files

* Filed herewith.
* * Furnished herewith.

Table of Contents

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: April 27, 2012