BERRY PETROLEUM CO
Form 10-Q/A
May 09, 2013
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q/A
(Amendment No. 1)
T Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended March 31, 2013
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 May 6, 2013 the registrant had 52,671,706 shares of Class A Common Stock ($0.01 par value) outstanding. The registrant also had 1,763,866 shares of Class B Stock ($0.01 par value) outstanding on May 6, 2013, all of which is held by a single holder.

EXPLANATORY NOTE

This Amendment No. 1 on Form 10-Q/A (the Amendment) amends our Quarterly Report on Form 10-Q for the three months ended March 31, 2013, originally filed with the Securities and Exchange Commission (SEC) on May 8, 2013 (the Original Filing). We are filing this Amendment solely for the purpose of amending the graphical presentation of crude oil prices on page 19 of the Original Filing. Part IV is also being amended to add as exhibits new certifications in accordance with Rule 13a-14(a) promulgated by the SEC under the Securities Exchange Act of 1934.

Except as described above, no other changes have been made to the Original Filing. The Original Filing continues to speak as of the date of the Original Filing, and we have not updated the disclosures contained therein to reflect any events which occurred at a date subsequent to the filing of the Original Filing.

BERRY PETROLEUM COMPANY
INDEX TO FORM 10-Q/A
March 31, 2013

Table of Contents

PART I. FINANCIAL INFORMATION

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. The following discussion and analysis should be read 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, 2012, included in our Annual Report on Form 10-K and the Condensed Financial Statements included elsewhere herein.

Our revenue, profitability and future growth rate depend on many factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices have been volatile and may fluctuate widely in the future. The following charts highlight the quarterly average NYMEX price trends for crude oil and natural gas since the first quarter of 2010:

Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and natural gas reserves. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity or ability to finance planned capital expenditures. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil prices may result in significant non-cash fair value losses being incurred on our oil derivatives, which could cause us to experience net losses when prices rise.

Steam costs are a significant variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of natural gas used to generate steam. We benefit from lower natural gas prices as 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. In addition, production rates, labor and equipment costs, maintenance expenses and production taxes influence our operating costs. Our results of operations may fluctuate from period to period based on such factors.

LinnCo, LLC Merger

On February 20, 2013, the Company, Linn Energy, LLC (Linn), LinnCo, LLC (LinnCo), Linn Acquisition Company, LLC, a direct wholly owned subsidiary of LinnCo (LinnCo Merger Sub), Bacchus HoldCo, Inc., a direct wholly owned subsidiary of the Company (HoldCo), and Bacchus Merger Sub, Inc., a direct wholly owned subsidiary of HoldCo (Bacchus Merger Sub), entered into a definitive Agreement and Plan of Merger (the “Merger Agreement”), pursuant to which LinnCo agreed to acquire the Company in an all-stock transaction in which the Company's stockholders would receive 1.25 shares representing limited liability company interests in LinnCo (LinnCo Shares) for each share of the Company's common stock.

Table of Contents

The transaction will occur through multiple steps. First, the Company will engage in a holding company merger (the HoldCo Merger) involving HoldCo and Bacchus Merger Sub. In the HoldCo Merger, Bacchus Merger Sub will merge with and into the Company, with the Company surviving as a wholly owned subsidiary of HoldCo, and each issued and outstanding share of the Company's Class A common stock and Class B common stock will convert into the right to receive one equivalent share of Class A common stock and one equivalent share of Class B common stock, respectively, of HoldCo.

Second, promptly after the HoldCo Merger, the Company will be converted into a limited liability company. Third, promptly following such conversion, HoldCo will be merged with and into LinnCo Merger Sub, with LinnCo Merger Sub surviving as the surviving company (the LinnCo Merger). In the LinnCo Merger, each share of Holdco's Class A common stock and each share of Holdco's Class B common stock will be converted into 1.25 LinnCo Shares.

Finally, promptly following the LinnCo Merger, LinnCo will contribute all of the outstanding equity interests in LinnCo Merger Sub (and therefore also its indirect ownership interest in the Company) to Linn (the “Contribution”) in exchange for the issuance to LinnCo (the “Issuance”) of newly issued Linn common units. The number of Linn common units to be issued to LinnCo in the Issuance will be equal to the greater of (i) the aggregate number of LinnCo Shares issued in the LinnCo Merger and (ii) the number of Linn common units required to cause LinnCo to own no less than one-third of all of the outstanding Linn common units following the Contribution. In addition, for three years following the closing, Linn will pay to LinnCo additional cash distributions in the amount of $6 million per year.

The closing of the transactions is subject to customary closing conditions, including approval of the Merger Agreement and the transactions contemplated thereby by the stockholders of the Company and the holders of the shares of LinnCo and Linn, receipt of certain opinions by the parties with respect to the tax-free nature of the transactions, and other customary conditions.

On March 1, 2013, a purported stockholder class action captioned Nancy P. Assad Trust v. Berry Petroleum Company, et al. was filed in the United States District Court for the District of Colorado. The case was dismissed by the Court on March 20, 2013 for lack of subject matter jurisdiction, and refiled in the District Court for the City and County of Denver, Colorado on March 21, 2013, Case No. 2013CV031365. On April 5, 2013, the plaintiff filed an amended complaint alleging that the individual Company director defendants breached their fiduciary duties in connection with the proposed merger transaction with Linn and LinnCo by engaging in an unfair sales process that resulted in an unfair price for the Company, and that the entity defendants aided and abetted those breaches of fiduciary duty. The amended complaint seeks a declaration that the proposed merger transactions are unlawful and unenforceable, an order directing the individual director defendants to comply with their fiduciary duties, an injunction against consummation of the merger transactions or, in the event they are so completed, rescission of the transactions, an award of fees and costs, including attorneys' and experts' fees and expenses, and other relief.
On April 12, 2013, a second purported stockholder class action captioned David S. Hall v. Berry Petroleum Company, et al. was filed in the Court of Chancery of the State of Delaware, C.A. No. 8476-VCG. The plaintiff in this case makes allegations, and seeks relief similar to the allegations made and relief sought in the Assad case.
A response has not yet been filed with respect to either complaint. However, the Company believes the claims relating to the merger are without merit, and intends to defend such actions vigorously.
Notable First Quarter 2013 Items

- Increased oil production by 2% from the fourth quarter of 2012
- Generated discretionary cash flow of $133.9 million from production of 39,676 BOE/D, of which 79% was oil[1]
- Generated an operating margin of $48.80 per BOE, supported by sales of our California heavy oil at a $10.18 average premium to WTI during the quarter[1]
- Average daily production from our Diatomite properties increased 7% from the fourth quarter of 2012
-

Production from our North Midway-Sunset—New Steam Floods (NMWSS—NSF) properties, which include McKittrick, averaged 2,355 BOE/D, an 11% increase from the fourth quarter of 2012
- Production from our Permian properties averaged 8,105 BOE/D, a 2% increase from the fourth quarter of 2012
- Drilled 20 Uinta wells, 10 Permian wells and 44 Diatomite wells

(1) Discretionary cash flow and operating margin are considered non-GAAP performance measures and reference should be made to "Reconciliation of Non-GAAP Measures" for further explanation as well as reconciliations to the most directly comparable GAAP measures.

Table of Contents

Results of Operations.

In the first quarter of 2013, we reported net earnings of $32.4 million, or $0.58 per diluted share, and net cash flows from operations of $91.7 million. Net earnings in the first quarter of 2013 included a loss on derivatives of $1.9 million resulting from non-cash changes in fair values, lease write offs of $1.5 million and $1.3 million of professional fees associated with the pending LinnCo merger, in each case net of income taxes.

Operating Data.

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

	March 31, 2013	%	March 31, 2012	%	December 31, 2012	%
Heavy oil production (BOE/D)	19,566	50	17,005	49	19,058	48
Light oil production (BOE/D)	11,588	29	8,091	24	11,591	30
Total oil production (BOE/D)	31,154	79	25,096	73	30,649	78
Natural gas production (Mcf/D)	51,132	21	56,105	27	53,106	22
Total (BOE/D)(1)	39,676	100	34,447	100	39,500	100
Oil and natural gas, per BOE:						
Average realized sales price	$75.27		$74.33		$70.51	
Average sales price including cash derivative settlements	$75.95		$74.44		$72.47	
Oil, per BOE:						
Average WTI price	$94.36		$103.03		$88.23	
Price sensitive royalties(2)	(2.81)		(4.24)		(2.65)	
Location differential and other(3)	(1.25)		(1.48)		0.79	
Oil derivatives non-cash amortization(4)	0.89		(1.14)		(1.03)	
Oil revenue	$91.19		$96.17		$85.34	
Add: Oil derivatives non-cash amortization(4)	—		1.14		1.03	
Oil derivative cash settlements(5)	(0.89)		(3.08)		1.57	
Average realized oil price	$90.30		$94.23		$87.94	
Natural gas price:						
Average Henry Hub price per MMBtu	$3.34		$2.72		$3.41	
Conversion to Mcf	0.22		0.18		0.24	
Natural gas derivatives non-cash amortization(4)	—		(0.01)		—	
Location differential and other	(0.09)		(0.30)		(0.14)	
Natural gas revenue per Mcf	$3.47		$2.59		$3.51	
Add: Natural gas derivatives non-cash amortization(4)	—		0.01		—	
Natural gas derivative cash settlements(5)	(0.01)		0.92		(0.03)	
Average realized natural gas price per Mcf	$3.46		$3.52		$3.48	

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

(2) Our Formax property in SMWSS—Steam Floods is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2013 base price of $17.78 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in the first quarter of 2013 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $18.14 in 2014.

(3) In California, the per barrel oil posting differential at March 31, 2013 was $9.10, ranged from $9.10 to $11.02 during the first quarter of 2013 and averaged $10.18 during the first quarter of 2013. In Utah, the per barrel oil posting differential at March 31, 2013 was ($16.50), ranged from ($14.50) to ($16.50) during the first quarter of 2013 and averaged ($15.65) during the first quarter of 2013.

Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010.

(4) Recorded in the Condensed Statements of Operations under the caption oil and natural gas sales. At December 31, 2012, the entire balance of AOCL had been reclassified into earnings.

(5) Cash settlements on derivatives are 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 thousands except per share data) for the three month periods ended:

	March 31, 2013	March 31, 2012	1Q12 to 1Q13 Change		December 31, 2012	4Q12 to 1Q13 Change	
Oil sales	$250,777	$220,452	14	%	$231,766	8	%
Natural gas sales	15,995	13,201	21	%	17,145	(7	)%
Total oil and natural gas sales	$266,772	$233,653	14	%	$248,911	7	%
Electricity sales	7,589	5,980	27	%	8,586	(12	)%
Natural gas marketing	2,027	1,859	9	%	2,253	(10	)%
Gain on sale of assets	23	1,763	(99	)%	12	92	%
Interest and other income, net	475	747	(36	)%	307	55	%
Total revenues and other income	$276,886	$244,002	13	%	$260,069	6	%
Net earnings	$32,434	$33,898	(4	)%	$38,499	(16	)%
Diluted earnings per share	$0.58	$0.61	(5	)%	$0.69	(16	)%

Oil and Natural Gas Sales.

Oil and natural gas sales increased $33.1 million, or 14%, to $266.8 million in the first quarter of 2013 compared to the same period in 2012. The increase was primarily due to an increase in oil sales volumes between periods. Our oil sales volume increased 21% in the first quarter of 2013 compared to the first quarter of 2012, while our natural gas sales volumes decreased 10%. The oil sales volume increase was primarily due to increased oil production from each of our oil properties. Permian oil production in the first quarter of 2013 increased 2,065 BOE/D, or 44%, from the same period in 2012, Uinta oil production increased 1,525 BOE/D, or 49%, between periods, Diatomite oil production in the first quarter of 2013 increased 1,430 BOE/D, or 53%, from the same period in 2012, oil production for NMWSS—NSF increased 845 BOE/D, or 56%, between periods and South Midway-Sunset—Steam Floods (SMWSS—Steam Floods) oil production increased 285 BOE/D, or 2%, between periods. The decrease in natural gas sales volumes was primarily due to expected production declines from our E. Texas and Piceance properties, partially offset by increased natural gas production from our Permian and Uinta properties.

Oil and natural gas sales increased $17.9 million, or 7%, to $266.8 million in the first quarter of 2013 compared to the fourth quarter of 2012. The increase was primarily due to a 7% increase in the average realized sales price between periods, primarily due to an increase in oil sales volumes as a percentage of total sales volumes. In addition, oil sales volumes increased 2% in the first quarter of 2013 compared to the fourth quarter of 2012, while natural gas sales volumes decreased 6% between periods. The oil sales volume increase was primarily due to increased oil production from all of our oil properties with the exception of SMWSS—Steam Floods, which declined marginally as expected, and the Uinta, which was impacted by refinery constraints in the Utah region. Diatomite oil production increased 260 BOE/D, or 7%, between periods, NMWSS—NSF oil production increased 225 BOE/D, or 11%, from the fourth quarter of 2012, and Permian oil production increased 175 BOE/D, or 3%, between periods. The decrease in natural gas sales volumes was primarily due to expected field decline in E. Texas and the Piceance.

Table of Contents

Electricity Sales.

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

	Three Months Ended		
	March 31, 2013	March 31, 2012	December 31, 2012
Electricity			
Electricity sales (in thousands)	$7,589	$5,980	$8,586
Operating costs (in thousands)	$5,296	$5,017	$5,975
Electric power produced (MWh/D)	2,036	2,089	2,112
Electric power sold (MWh/D)	1,851	1,935	1,917
Average sales price per MWh	$44.77	$33.96	$41.30
Fuel gas cost per MMBtu (including transportation)	$3.55	$2.71	$3.51
Estimated natural gas volumes consumed to produce electricity (MMBtu/D)(1)	14,726	15,197	15,987

(1) Estimate is based on the historical allocation of fuel costs to electricity.

Electricity sales in the first quarter of 2013 increased 27% compared to the first quarter of 2012 primarily due to a 32% increase in the average sales price of electricity, partially offset by a 4% decrease in electric power sold. Electricity operating costs in the first quarter of 2013 increased 6% compared to the first quarter of 2012 largely due to a 31% increase in fuel gas cost, partially offset by a 3% decrease in electric power produced. Electricity sales decreased 12% in the first quarter of 2013 compared to the fourth quarter of 2012. Electricity sales in the fourth quarter of 2012 included a retroactive payment adjustment for capacity of $1.3 million from one of our electricity customers. As a result of our previously disclosed global settlement with various parties that became effective on November 23, 2011, we received retroactive payments for firm capacity that had been originally paid at "as available" capacity rates, and these payments represent the difference in rates over the disputed period. Excluding the retroactive payment adjustments, electricity sales in the first quarter of 2013 would have increased 5% compared to the fourth quarter of 2012 primarily due to an 8% increase in the average sales price of electricity partially offset by a 3% decrease in electric power sold. Electricity operating costs in the first quarter of 2013 decreased 11% compared to the fourth quarter of 2012 largely due to an 8% decrease in fuel gas volumes purchased.

Electricity Sales Contracts. We sell electricity produced by our cogeneration 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). Under these power purchase agreements (PPAs), 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 under the contracts for our Cogen 18 and Cogen 38 facilities will be based on market prices for electricity in California.

Our legacy PPAs for our Cogen 42 facilities expired in May 2012, at which time a transition PPA with Edison became effective. The transition PPA will terminate on July 1, 2014, upon the effectiveness of a seven-year contract for our Cogen 42 facilities pursuant to a competitive solicitation (the RFO PPA).

Our legacy PPA for our Cogen 38 facility expired in March 2012, at which time a transition PPA with PG&E became effective. We intend to participate in future CHP competitive solicitations for the sale of energy and capacity from our Cogen 38 facility, although there is no assurance we will be successful in entering into a new RFO PPA for this facility. Our transition PPA with PG&E will remain in effect until June 2015.

Our legacy PPA with PG&E for our Cogen 18 facility terminated on September 30, 2012 and was replaced with a new Public Utilities Regulatory Policy Act of 1978, as amended (PURPA) PPA with PG&E, effective October 1, 2012, for a term of seven years. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it continues to be eligible for PPAs pursuant to PURPA.

Under the PURPA PPA for our Cogen 18 facility and the transition PPAs for our Cogen 38 and Cogen 42 facilities, we will be paid the CPUC-determined SRAC energy price and a combination of firm and "as-available" capacity payments. Under the RFO PPA for our Cogen 42 facility, we will be paid a negotiated energy and capacity price stipulated in the contract.

Table of Contents

The following table summarizes our cogeneration facilities and related contract information as of March 31, 2013:

Facility	Type of Contract(1)	Purchaser	Contract Expiration
Cogen 42	Transition	Edison	Jul 2014(1)
Cogen 18	PURPA	PG&E	Sept 2019
Cogen 38	Transition	PG&E	Jun 2015(2)

(1) A new 7-year RFO PPA with Edison will be effective on July 1, 2014.

(2) We anticipate the current contract will be replaced by a long-term contract with a term of up to seven years pursuant to a future competitive solicitation.

Natural Gas Marketing.

We have long-term firm transportation contracts on the Rockies Express, Wyoming Interstate Company, 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 and utilize 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, 2013 and 2012 were $0.1 million and $0.1 million, respectively.

Gain on Sale of Assets.

In the first quarter of 2012, we recorded a $1.6 million gain in conjunction with the sale of our Nevada Assets. These gains were 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, 2013	March 31, 2012	December 31, 2012	March 31, 2013	March 31, 2012	December 31, 2012
Operating costs—oil and natural gas production(1)	$24.13	$17.30	$23.35	$86,148	$54,221	$84,862
Production taxes	3.02	3.40	2.57	10,784	10,658	9,326
DD&A—oil and natural gas production	19.07	15.30	18.44	68,084	47,956	67,023
General and administrative	6.24	5.66	5.03	22,278	17,741	18,293
Interest expense	6.91	6.41	5.97	24,687	20,104	21,690
Total	$59.37	$48.07	$55.36	$211,981	$150,680	$201,194

(1) Operating costs—oil and natural gas production includes firm transportation costs of $7.7 million and $7.0 million for the three months ended March 31, 2013 and 2012, respectively, and $7.1 million for the three months ended

December 31, 2012.

- Operating costs—oil and natural gas production in the first quarter of 2013 were $86.1 million, or $24.13 per BOE, compared to $54.2 million, or $17.30 per BOE, in the first quarter of 2012 and $84.9 million, or $23.35 per BOE, in the fourth quarter of 2012. The increase in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to an increase of approximately $14.6 million in steam costs, due to a 47% increase in the average volume of steam injected and a 31% increase in the price of natural gas used in steam generation. Also contributing to the increase in steam costs was $3.2 million of emissions expense related to California greenhouse gas regulatory compliance in the first quarter of 2013. Also increasing over the same time period were well workover costs and contract services primarily related to Permian wells added in the last 12 months, well servicing and maintenance costs in the Uinta and contract labor in the Diatomite.

The increase in operating costs—oil and natural gas production in the first quarter of 2013 compared to the fourth quarter

9

Table of Contents

of 2012 was primarily due to an increase in steam costs primarily due to $3.2 million of emissions expense related to California greenhouse gas regulatory compliance. Also increasing over the same time period were well servicing and maintenance costs and transportation costs, partly related to refinery constraints in the Utah region during the fourth quarter of 2012. These increases were partially offset by a decrease in well workover costs in the Permian between periods.

The following table sets forth information relating to steam injection for the three months ended:

	March 31, 2013	March 31, 2012	1Q12 to 1Q13 Change		December 31, 2012	4Q12 to 1Q13 Change	
Average net volume of steam injected (Bbl/D)	197,829	134,510	47	%	197,950	—	%
Fuel gas cost per MMBtu (including transportation)	$3.55	$2.71	31	%	$3.51	1	%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	66,171	45,591	45	%	61,998	7	%

- Production taxes in the first quarter of 2013 were $10.8 million, or $3.02 per BOE, compared to $10.7 million, or $3.40 per BOE, in the first quarter of 2012 and $9.3 million, or $2.57 per BOE, in the fourth quarter of 2012. 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 decrease in production taxes per BOE in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to a decrease in Utah severance taxes related to increased new well deductions associated with increased drilling in the first quarter of 2013. The increase in production taxes in the first quarter of 2013 compared to the fourth quarter of 2012 was primarily due to increases in estimated 2013 ad valorem taxes associated with development in the Permian and in Utah.

- Depreciation, depletion and amortization—oil and natural gas production (DD&A—oil and natural gas production) in the first quarter of 2013 was $68.1 million, or $19.07 per BOE, compared to $48.0 million, or $15.30 per BOE, in the first quarter of 2012 and $67.0 million, or $18.44 per BOE, in the fourth quarter of 2012. The increase in the first quarter of 2013 compared to the first quarter of 2012 and the fourth quarter of 2012 was primarily due to an increase in our DD&A rate. Our DD&A rate per BOE can fluctuate as a result of changes in the mix of our production, impairments, and changes in our proved reserves. Our DD&A rate per BOE in the first quarter of 2013 was 25% higher than in the first quarter of 2012 and 3% higher than in the fourth quarter of 2012. The higher DD&A rate per BOE in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to our development expenditures during the past twelve months and the increased contribution of our development properties with higher drilling and leasehold acquisition costs than our legacy California properties. In addition, our overall increase in production of 15% from the first quarter of 2013 to the first quarter of 2012 contributed to higher DD&A costs. The higher DD&A rate per BOE in the first quarter of 2013 compared to the fourth quarter of 2012 was primarily due to converting part of our Piceance proved reserves to unproved at December 31, 2012 as a result of the SEC's five year development limitation on proved undeveloped reserves.

- General and administrative expense (G&A) in the first quarter of 2013 was $22.3 million, or $6.24 per BOE, compared to $17.7 million, or $5.66 per BOE, in the first quarter of 2012 and $18.3 million, or $5.03 per BOE, in the fourth quarter of 2012. The increase in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to $2.1 million of professional fees associated with the pending LinnCo merger, an increase in employee compensation and benefits resulting from new personnel hired during the previous twelve months, as well as general pay increases. The increase in the first quarter of 2013 compared to the fourth quarter of 2012 was primarily due to $2.1 million related to professional fees associated with the pending LinnCo merger, director compensation of $1.1

million recorded in the first quarter of 2013 and new personnel hired and general pay increases during the first quarter of 2013.

Table of Contents

• The following table sets forth components of interest expense for the periods presented:

	Three Months Ended		
(in thousands)	March 31, 2013	March 31, 2012	December 31, 2012
Senior subordinated notes	$—	$4,125	$—
Senior notes	19,885	16,397	19,885
Credit facility	4,412	2,938	3,639
Amortization of debt issuance costs and net discount	1,709	2,038	1,680
Amortization of AOCL	—	(647)	—
Other	480	443	423
Capitalized interest	(1,799)	(5,190)	(3,937)
	$24,687	$20,104	$21,690

Interest expense in the first quarter of 2013 was $24.7 million, or $6.91 per BOE, compared to $20.1 million, or $6.41 per BOE, in the first quarter of 2012 and $21.7 million, or $5.97 per BOE, in the fourth quarter of 2012. The increase in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to the issuance of our 2022 Notes in March 2012, a decrease in capitalized interest and an increase in the amount outstanding under our credit facility. These increases were partially offset by decreases in interest payments related to the repurchase of $150 million aggregate principal amount of our 2014 Notes and related to the redemption of our 2016 Notes. The increase in the first quarter of 2013 compared to the fourth quarter of 2012 was primarily due a decrease in capitalized interest and an increase in the amount outstanding under our credit facility.

Dry Hole, Abandonment, Impairment and Exploration. For the three months ended March 31, 2013, we incurred dry hole, abandonment, impairment and exploration expense of $1.0 million, primarily related to plugging and abandonment activities, primarily in California, and additional dry hole costs associated with our Borden County appraisal wells that were written off in the fourth quarter of 2012. For the three months ended March 31, 2012, we incurred dry hole, abandonment, impairment and exploration expense of $3.1 million primarily for the purchase of seismic data and plugging and abandonment activities.

Impairment of Oil and Natural Gas Properties. In the three months ended March 31, 2013, we wrote off $2.5 million related to the expiration of certain leases in the Permian.

Table of Contents

Realized and Unrealized Loss (Gain) 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.

	Three Months Ended		
(in thousands)	March 31, 2013	March 31, 2012	December 31, 2012
Cash (receipts) payments:			
Commodity derivatives—oil	$(2,470)	$7,069	$(4,280)
Commodity derivatives—natural gas(1)	61	(19,381)	149
Total cash (receipts) payments	$(2,409)	$(12,312)	$(4,131)
Mark-to-market loss (gain):			
Commodity derivatives—oil	$3,693	$24,363	$(4,660)
Commodity derivatives—natural gas(1)	(547)	16,430	485
Total mark-to-market loss (gain)	$3,146	$40,793	$(4,175)
Total realized and unrealized loss (gain) on derivatives, net	$737	$28,481	$(8,306)

(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 was recorded in the Condensed Statements of Operations under the caption realized and unrealized loss on derivatives, net.

Income Tax Expense. The effective income tax rate for the three months ended March 31, 2013 and 2012 was 39.0% and 37.8%, 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.

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, 2013 Gross Production Wells		Net Production Wells
SMWSS—Steam Floods	—		—
NMWSS—Diatomite	44		44
NMWSS—New Steam Floods	—		—
Permian	16	(1)	10
Uinta	20		18
E. Texas	—		—
Piceance	—		—
Total	80		72

(1) Includes six non-operated wells in which we have an average interest of approximately 0.68% each, or approximately 0.04 total net wells, and 10 gross operated wells.

Properties.

We currently have seven asset teams, as follows: SMWSS—Steam Floods, North Midway-Sunset (NMWSS)—Diatomite, NMWSS—NSF, 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. These are our legacy assets in California, and we expect total average production to slowly decline over time. In the second quarter of 2013, we plan to continue development at Ethel D, where we plan to drill seven new producing wells and four steam injection wells, as well as redrill one producing well. Also during the second quarter of 2013, we plan to drill two horizontal producing wells at Formax, as well as seven new producing wells and seven recompletions at Placerita. Average daily production in the first quarter of 2013 from all of our SMWSS—Steam Floods assets was approximately 13,095 BOE/D compared to 13,070 BOE/D in the fourth quarter of 2012.

NMWSS—Diatomite. Our NMWSS—Diatomite asset team includes our Diatomite properties in the San Joaquin Valley. We are continuing to refine our development approach by using real-time performance monitoring and surveillance, and have increased our focus on redevelopment areas. We expect these efforts to increase the number of active completions and improve the recovery of the resource in leases with existing production and infrastructure. In the first quarter of 2013, we drilled 27 new producing wells and 17 replacement wells, and plan to drill an additional 12 new producing wells and 14 replacement wells in the second quarter of 2013. Average daily production from our NMWSS—Diatomite assets in the first quarter of 2013 was approximately 4,115 BOE/D, a 7% increase from 3,855 BOE/D in the fourth quarter of 2012.

NMWSS—New Steam Floods. Our NMWSS—NSF asset team includes our non-Diatomite North Midway-Sunset assets including our McKittrick, Main Camp, Fairfield, Pan, and USL-12 properties. In the first quarter of 2013, we drilled the first seven of the 50 steam injection wells we plan to drill at McKittrick during 2013, and we plan to drill the remaining 43 steam injection wells in the second quarter of 2013. We also added an additional steam generator at

McKittrick in the first quarter of 2013, increasing the steam capacity at McKittrick to approximately 25,000 barrels of steam per day. In addition, during the first quarter of 2013, we began expanding our Main Camp oil processing facility, and expect to complete the expansion in the second quarter of 2013. Average daily production from all of our NMWSS—NSF assets in the first quarter of 2013 was approximately 2,355 BOE/D, a 11% increase from 2,130 BOE/D in the fourth quarter of 2012.

Permian. During the first quarter of 2013, we drilled ten net wells using a three-rig program, and we plan to continue at this pace, drilling ten additional net wells in the second quarter of 2013. While our Permian production continues to increase, constraints in the form of higher line pressure, shut-ins, periodic gas plant downtime and ethane rejection have continued as a result of record activity levels in the area. Average daily production in the first quarter of 2013 from our Permian assets was approximately 8,105 BOE/D, a 2% increase from 7,965 BOE/D in the fourth quarter of 2012.

Uinta. During the first quarter of 2013, we drilled 20 gross (18 net) wells at our Uinta properties utilizing a three-rig drilling program. Of the 20 wells drilled, 19 were Wasatch/Green River commingled wells. Our Uinta production in the first quarter of 2013 was impacted by delayed completion activity as we worked off inventory in the field resulting from refinery turnarounds. In the first quarter of 2013, we began shipping crude oil via rail to markets outside of Utah. In the second quarter of 2013, we plan to drill 20 gross wells utilizing a two-rig program, including five in Brundage Canyon, four in Lake Canyon, and 11 in Ashley National forest. Average daily production from our Uinta assets was approximately 7,305 BOE/D in the first quarter of 2013, a 3% decrease from 7,500 BOE/D in the fourth quarter of 2012.

E. Texas. We have deferred drilling activities in E. Texas while we focus on higher return oil development opportunities at our other properties. Average daily production in the first quarter of 2013 from the E. Texas assets was approximately 13 MMcf/D compared to 14 MMcf/D in the fourth quarter of 2012.

Piceance. We have deferred drilling activities in the Piceance while we focus on higher return oil development opportunities at our other properties. Average daily production in the first quarter of 2013 from the Piceance assets was approximately 15 MMcf/D compared to 16 MMcf/D in the fourth quarter of 2012.

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, 2013, we had a working capital deficit of approximately $24.7 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 commodity prices on our cash flow. As of March 31, 2013, we had approximately 65% and 60% of our expected 2013 and 2014 oil production hedged, respectively. 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 2013 and 2014. 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. As of March 31, 2013, our credit facility, which matures on May 13, 2016, had a borrowing base of $1.4 billion, subject to lender commitments. At March 31, 2013, lender commitments under the facility were $1.2 billion.

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, 2013, there were $653.6 million in outstanding borrowings under the credit facility and $23.2 million in outstanding letters of credit, leaving $523.2 million in borrowing capacity available 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 semi-annual redetermination in April 2013 did not result in any changes to the borrowing base, lender commitments, or other terms of the credit facility.

Table of Contents

The credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of at least 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 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, 2013, we were in compliance with all financial covenants and have complied with all financial covenants for all prior periods presented.

Outstanding Long-Term Indebtedness. As of March 31, 2013 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.

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.

	Three Months Ended	
(in thousands)	March 31, 2013	March 31, 2012
Net cash provided by operating activities	$91,698	$155,406
Net cash used in investing activities	(178,879)	(169,077)
Net cash provided by financing activities	86,974	57,369
Net (decrease) increase in cash and cash equivalents	$(207)	$43,698

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 decrease in net cash provided by operating activities of $63.7 million in the first three months of 2013 compared to the first three months of 2012 was primarily due to changes in current assets and liabilities (including bank overdraft but excluding cash), which decreased cash provided by operating activities by $51.5 million.

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 $9.8 million in net cash used in investing activities in the first three months of 2013 compared to the first three months of 2012 was primarily due to an increase in development and exploration activity partially offset by decreases in acquisitions, capitalized interest and divestitures. Investing activities in the first three months of 2012 included proceeds from the sale of our Nevada assets.

Table of Contents

Financing Activities. Net cash provided by financing activities in the first three months of 2013 included net borrowings of $90.7 million under our credit facility. 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.

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.

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 2013. 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.

Recent Accounting Standards and Updates.

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

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, cash settlements from the early termination of natural gas derivatives and cash premiums to repurchase debt. 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, 2013
Net cash provided by operating activities	$91,698
Net increase in current assets	12,564
Net decrease in current liabilities, including book overdraft	29,622
Discretionary cash flow	$133,884

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

(per BOE)	Three Months Ended March 31, 2013

Average sales price including cash derivative settlements	$75.95
Average operating costs—oil and natural gas production	24.13
Average production taxes	3.02
Average operating margin	$48.80

Table of Contents

PART II. OTHER INFORMATION

Item 6. Exhibits

Exhibit No.	Description of Exhibit
2.1	Agreement and Plan of Merger, dated as of February 20, 2013, by and among Berry Petroleum Company, Bacchus HoldCo, Inc., Bacchus Merger Sub, Inc., LinnCo, LLC, Linn Acquisition Company, LLC and Linn Energy, LLC (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on February 21, 2013, File No. 1-09735).
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 with the Original Filing.
** 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
Vice President and Controller
(Principal Accounting Officer)
Date: May 9, 2013