UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[X] Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

For the quarterly period ended March 31, 2003
Commission file number 1-9735

BERRY PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

DELAWARE	77-0079387
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5201 Truxtun Avenue, Suite 300, Bakersfield, California	93309-0640
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (661) 616-3900

Former name, Former Address and Former Fiscal Year, if Changed Since Last Report:
NONE

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 such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
YES (X) NO ( )

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). YES (X) NO ( )

The number of shares of each of the registrant's classes of capital stock outstanding as of March 31, 2003, was 20,860,070 shares of Class A Common Stock ($.01 par value) and 898,892 shares of Class B Stock ($.01 par value). All of the Class B Stock is held by a shareholder who owns in excess of 5% of the outstanding stock of the registrant.

BERRY PETROLEUM COMPANY
MARCH 31, 2003
INDEX

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Balance Sheets
(In Thousands, Except Share Information)

	March 31, 2003 (Unaudited)	December 31, 2002
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 11,179	$ 9,866
Short-term investments available for sale	660	660
Accounts receivable	20,583	15,582
Prepaid expenses and other	2,598	2,597
Total current assets	35,020	28,705
Oil and gas properties (successful efforts basis), buildings and equipment, net	226,814	228,475
Other assets	876	893
	$ 262,710	$ 258,073
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 15,792	$ 19,189
Accrued liabilities	3,346	6,470
Federal and state income taxes payable	5,689	2,612
Fair value of derivatives	3,408	4,123
Total current liabilities	28,235	32,394
Long-term liabilities:		
Deferred income taxes	34,779	33,866
Long-term debt	15,000	15,000
Abandonment obligation	5,041	4,596
Fair value of derivatives	146	159
Total long-term liabilities	54,966	53,621
Shareholders' equity:		
Preferred stock, $.01 par value; 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, $.01 par value:		
Class A Common Stock, 50,000,000 shares authorized; 20,860,070 shares issued and outstanding at March 31, 2003 (20,852,695 at December 31, 2002)	209	209
Class B Stock, 1,500,000 shares authorized; 898,892 shares issued and outstanding (liquidation preference of $899)	9	9
Capital in excess of par value	49,065	49,052
Accumulated other comprehensive loss	(2,133)	(2,569)
Retained earnings	132,359	125,357
Total shareholders' equity	179,509	172,058
	$ 262,710	$ 258,073

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

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Income Statements
Three Month Periods Ended March 31, 2003 and 2002
(In Thousands, Except Per Share Information)
(Unaudited)

	2003	2002
Revenues:		
Sales of oil and gas	$ 34,354	$ 19,678
Sales of electricity	12,880	7,314
Interest and other income, net	20	378
	47,254	27,370
Expenses:		
Operating costs - oil and gas production	13,184	8,086
Operating costs - electricity generation	12,880	6,983
Depreciation, depletion and amortization	4,454	3,992
General and administrative	2,257	1,862
Recovery of electricity receivables	-	(3,631)
Dry hole and abandonment	2,487	-
Interest	209	423
	35,471	17,715
Income before income taxes	11,783	9,655
Provision for income taxes	2,606	1,035
Net income	$ 9,177	$ 8,620
Basic net income per share	$ .42	$ .40
Diluted net income per share	$ .42	$ .40
Cash dividends per share	$ .10	$ .10
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,758	21,732
Effect of dilutive securities:		
Stock options	120	50
Other	42	29
Weighted average number of shares of capital stock used to calculate diluted net income per share	21,920	21,811

Condensed Statements of Comprehensive Income
Three Month Periods Ended March 31, 2003 and 2002
(in Thousands)
(Unaudited)

	2003	2002
Net income	$ 9,177	$ 8,620
Unrealized losses on derivatives, (net of income taxes of $1,422 and $1,193, respectively)	(2,133)	(1,790)
Comprehensive income	$ 7,044	$ 6,830

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

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Statements of Cash Flows
Three Month Periods Ended March 31, 2003 and 2002
(In Thousands)
(Unaudited)

	2003	2002
Cash flows from operating activities:		

Net income	$ 9,177	$ 8,620
Depreciation, depletion and amortization	4,454	3,992
Dry hole and abandonment	2,487	-
Deferred income tax liability	913	187
Other, net	59	59
Net working capital provided by operating activities	17,090	12,858
Decrease (increase) in accounts receivable, prepaid expenses and other	(5,287)	7,565
Decrease in current liabilities	(3,444)	(3,936)
Net cash provided by operating activities	8,359	16,487
Cash flows from investing activities:		
Capital expenditures	(2,324)	(4,333)
Property acquisitions	(2,547)	-
Net cash used in investing activities	(4,871)	(4,333)
Cash flows from financing activities:		
Payment of long-term debt	-	(5,000)
Dividends paid	(2,175)	(2,173)
Net cash used in financing activities	(2,175)	(7,173)
Net increase in cash and cash equivalents	1,313	4,981
Cash and cash equivalents at beginning of year	9,866	7,238
Cash and cash equivalents at end of period	$ 11,179	$ 12,219
Supplemental non-cash activity:		
Decrease in fair value of derivatives:		
Current (net of income taxes of $1,363 and $1,193 in 2003 and 2002, respectively)	$ 2,045	$ 1,790
Non-current (net of income taxes of $59 and $0 in 2003 and 2002, respectively)	88	-
Net decrease to accumulated other comprehensive income	$ 2,133	$ 1,790

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

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Notes to Condensed Financial Statements
March 31, 2003
(Unaudited)

1. All adjustments which are, in the opinion of management, necessary for a fair presentation of the Company's financial position at March 31, 2003 and December 31, 2002 and results of operations and cash flows for the three month periods ended March 31, 2003 and 2002 have been included. All such adjustments are of a normal recurring nature. The results of operations and cash flows are not necessarily indicative of the results for a full year.

2. The accompanying unaudited financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2002 financial statements. The December 31, 2002 Form 10-K should be read in conjunction herewith. The year-end condensed balance sheet was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America.

3. The Company has leased approximately 208,000 acres in Kansas and 54,000 acres in Illinois for the purpose of exploring for economic concentrations of coalbed methane for a total lease cost

of approximately $6.0 million. The Company drilled a five-well pilot on the Illinois acreage in the fourth quarter of 2002 which, as anticipated, continues to dewater. The results of this pilot are not yet conclusive and are not expected to be known until the latter half of 2003. An additional five-well pilot was drilled in the Wabaunsee County portion of the Kansas acreage late in the fourth quarter of 2002. On this pilot, initial water production was less than expected with no resulting gas pressure buildup and the gas content of the coals was significantly lower than anticipated. Consequently, the Company believes this pilot will not produce commercial quantities of natural gas and, therefore, wrote off the cost to drill the five-well pilot and the associated leased acreage. The total amount charged to operations in the first quarter of 2003 was $2.5 million. The leased acreage in Kansas also includes acreage positions in Jackson County and Osage County. The Company is evaluating the location and method of drilling additional test wells in these areas.

4. As allowed in Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation," the Company continues to apply Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees," and related interpretations in recording compensation related to its plan. The supplemental disclosure requirements of SFAS No. 123, as amended in SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure," related to the Company's stock option plan is presented below:

4. (cont'd) Under SFAS No. 123, compensation cost would be recognized for the fair value of the employee's option rights. The fair value of each option was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions for option grants made in 2002 (there were no grants issued in the first quarter of 2003):

	2002
Yield	2.55%
Expected option life - years	7.5
Volatility	33.45%
Risk-free interest rate	4.09%

Had compensation cost for the Company's stock based compensation plan been based upon the fair value at the grant dates for awards under the plan consistent with the method of SFAS No. 123 using the Black Scholes Method, the Company's compensation cost, net of related tax effects, net income and earnings per share would have been recorded as the proforma amounts indicated below for the three months ended March 31, 2003 and 2002 (in thousands, except per share data):

	2003	2002
Compensation cost, net of income taxes		
As reported	$ 20	$ 5
Pro forma	151	161
Net income:		
As reported	9,177	8,620
Pro forma	9,046	8,464
Basic net income per share:		

As reported	.42	.40
Pro forma	.42	.39
Diluted net income per share:		
As reported	.42	.40
Pro forma	.41	.39

The Company continues to evaluate the best method for fair-market value pricing of stock options as there is no universal acceptance of the Black Scholes Method as the most appropriate method for companies such as Berry.

5. In April 2003, the Company entered into a Purchase and Sale Agreement with Williams Production RMT Company to acquire its Brundage Canyon, Utah properties in the Uinta Basin for approximately $49 million. The Company anticipates the acquisition will close in the third quarter of 2003. The Brundage Canyon properties, located in northeastern Utah, consist of approximately 43,500 net acres, and are currently producing approximately 2,200 net BOE/day of light crude oil and natural gas and the Company estimates the proved reserves at 8.6 million BOE (75% light oil and 25% natural gas). The Company expects to fund the acquisition from cash generated from operations and borrowings from its credit facility.

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

Results of Operations

The Company earned net income of $9.2 million, or $.42 per share, on revenues of $47.3 million in the first quarter of 2003, up 7% from net income of $8.6 million, or $.40 per share, in the first quarter of 2002, and up 31% from net income of $7 million, or $.32 per share, in the fourth quarter of 2002. Results in the first quarter of 2003 include a pre-tax write off of $2.5 million, representing the cost of a pilot project and associated leasehold acquisition costs in Kansas. The results in the first quarter of 2002 include the pre-tax gain from the recovery of a $3.6 million receivable for electricity sales which was written off in 2001.

The following table presents certain comparative operating data for the first quarters of 2003 and 2002 and the fourth quarter of 2002.

	Three Months Ended		
	Mar 31, 2003	Mar 31, 2002	Dec 31, 2002
Oil and gas:			
Net production - BOE/day	15,736	13,799	15,208
Per BOE:			

Average sales price	$ 24.23	$ 15.87	$ 20.41
Operating costs(1)	8.78	5.95	9.57
Production taxes	.53	.56	.60
Total operating costs	9.31	6.51	10.17
Depreciation, depletion and amortization (DD&A)	3.15	3.21	2.90
General and administrative expenses(G&A)	1.59	1.50	1.26
Interest expense	.15	.34	.13
Electricity:			
Electric power produced - Mwh/day	2,137	2,051	2,126
Electric power sold - Mwh/day	1,951	1,890	1,860
Average sales price - $/Mwh	$ 73.39	$ 36.35	$ 43.97
Fuel gas cost - $/MMBtu	5.40	2.49	3.99

(1)Including monthly expenses in excess of monthly revenues from cogeneration operations of $1.72, $.31 and $2.97 in the three months ended March 31, 2003, March 31, 2002 and December 31, 2002, respectively.

Operating income from oil and gas operations in the first quarter of 2003 was $14.3 million, up 86% from $7.7 million in the first quarter of 2002 and up 36% from $10.5 million in the fourth quarter of 2002.

Operating income increased in the first quarter of 2003 due to increased crude oil production and higher crude oil and electricity sales prices. These factors were offset somewhat by higher fuel gas prices, higher DD&A and higher G&A costs.

The Company's production of oil and gas (BOE/day) in the first quarter of 2003 improved to 15,736, up 14% from 13,799 in the first quarter of 2002 and up 3% from 15,208 in the fourth quarter of 2002. Production in the first quarter of 2002 had not yet recovered from the effects of the temporary suspension of steaming operations in 2001 due to the effects of the California energy crisis. The Company injected approximately 60,000 barrels of steam per day in 2002. This factor and the contribution of the wells drilled and workovers completed under the 2002 capital budget account for the majority of the increase in production from the first quarter of 2002. Assuming stable natural gas and crude oil prices and with the completion of the 2003 budget, the Company's target is to average approximately 16,400 BOE/day for the year with a 2003 exit rate of approximately 17,700 BOE/day.

The average price received for the Company's heavy crude oil in the first quarter of 2003 was $24.23 per barrel, up 53% and 19% from the first quarter of 2002 and the fourth quarter of 2002, respectively.

The Company primarily uses zero-cost bracketed collars based on WTI crude oil prices to protect cash flow from a severe crude oil price decline. At March 31, 2003, the Company had hedged 6,500 barrels per day for the remainder of 2003 whereby the Company could capture an average of $3.88 below a WTI price of $22.31 per barrel and may give up to an average of $4.48 above $25.79 per barrel. The Company has also hedged 5,000 barrels per day in the first quarter of 2004 and 4,000 barrels per day for the second through fourth quarters of 2004. In 2004, the Company could capture up to an average of $3.64 per barrel below approximately $22.39 per barrel and may give up to an average of $4.24 per barrel above $25.65 per barrel. In addition to these collars, the Company entered into a series of crude oil swaps based on WTI pricing on 1,500 barrels per day at prices ranging from $25.68 to $27.17 covering the six month period from May 1, 2003 to October 31, 2003 and 1,000 barrels per day for the six months beginning November 2003 for an average price of $25.00. The Company nets its oil hedging gains or losses into its revenues from the sales of oil and gas.

On March 1, 2002, the Company received payment in full for certain past due receivables from Southern California Edison Company which were previously written off by the Company in 2001. The Company recognized pre-tax gains from the recovery of $3.6

million of the receivables, $.1 million in additional interest and $.5 million in additional capacity revenue for periods in 2001 when the Company was compelled to shut-in its cogeneration plants due to the payment default of the utility.

In January 2003, Standard Offer contract terms were reinstated on the power produced from one of two turbines at the Company's cogeneration facility located in the Placerita oilfield in Los Angeles County and on both the 38 megawatt and 18 megawatt facilities located on the Company's Midway-Sunset properties in Kern County, California. Under the terms of these agreements, the Company received an average of $72.89 per Mwh in the first quarter of 2003. The primary benefit of these contracts is that the Company's electricity revenues are based on the cost of natural gas. Therefore, these contracts mitigate the Company's exposure to higher operating costs based on higher natural gas costs. The Company consumes approximately 37,000 MMBtu of natural gas per day for use in generating steam and of this total, approximately 72% is consumed in the Company's cogeneration operations.

Operating expenses for the first three months of 2003 were $13.2 million, up 63% from $8.1 million, in the first quarter of 2002, but down 7% from $14.2 million in the fourth quarter of 2002. The cost of natural gas used in the Company's steaming operations increased from $2.49 per MMBtu in the first quarter of 2002 to $5.40 in the first quarter of 2003, resulting in significantly higher steam costs in the 2003 quarter compared to the first quarter of 2002. The cost of natural gas per MMBtu was $5.40 in the first quarter of 2003, 35% higher than $3.99 in the fourth quarter of 2002. However, the Company received higher electricity revenues in the 2003 quarter due to the reinstated Standard Offer contracts effective January 2003, which resulted in lower operating costs compared to the fourth quarter of 2002. In addition to steam costs, the cost of supplies and equipment, chemicals, utilities and insurance increased compared to the first quarter of 2002. Operating costs per BOE of $9.31 in the first quarter of 2003 were in line with the Company's 2003 target of $8.50 to $9.50 per BOE.

To protect the cash flow from future increases in natural gas prices on the fixed price contract on Unit 1 of the Company's Placerita cogeneration facility, in April 2003, the Company entered into natural gas swaps on a total volume of 5,000 MMBtu per day at a fixed price of $4.85 per MMBtu for the period June 2003 through June 2006, thereby helping to control steam costs.

DD&A for the first quarter of 2003 was $4.5 million, up 13% from $4.0 million in the first quarter of 2002 and up 10% from $4.1 million in the fourth quarter of 2002. The increase in the first quarter of 2003 was primarily related to higher depreciation rates for assets using the units of production method due to higher production levels and depreciation on additions from recent capital budget programs. On a per BOE basis, DD&A was $3.15 in the first quarter of 2003, down from $3.21 in the first quarter of 2002, but up from $2.90 in the fourth quarter of 2002. Assuming stable natural gas and crude oil prices, the Company currently anticipates that DD&A will average between $3.15 and $3.25 per BOE during 2003.

G&A for the first quarter of 2003 was $2.3 million, or $1.59 per BOE, up 21% from $1.9 million, or $1.50 per BOE, in the first quarter of 2002 and up 28% from $1.8 million, or $1.26 per BOE, in the fourth quarter of 2002. The increase in the first quarter of 2003 was due primarily to higher payroll, rent, insurance, accounting fees and property evaluation costs related to the Company's efforts to expand into a new core area outside of California.

In 2002 and early 2003, the Company leased a total of approximately 208,000 acres in Kansas and 54,000 acres in Illinois for the purpose of exploring for economic concentrations of coalbed methane gas for a total lease cost of approximately $6.0 million. The Company drilled a five-well pilot on the Illinois acreage in the fourth quarter of 2002 which, as anticipated, continues to dewater. The results of this pilot are not yet conclusive and are not expected to be known until the latter half of 2003. The Company also drilled a five-well pilot in the Wabaunsee County portion of the Kansas acreage late in the fourth quarter of 2002. On this pilot, initial water production was less than expected with no resulting gas pressure buildup and the gas content of the coals was significantly lower than anticipated. Consequently, the Company believes this pilot will not produce commercial quantities of natural gas and, therefore, wrote off the cost to drill the five-well pilot and the associated leased acreage. The total amount charged to operations in the first quarter of 2003 was $2.5 million. The leased acreage in Kansas also includes positions in Jackson County and Osage County. The Company is evaluating the location and method of drilling additional test wells in these areas.

The Company experienced an effective tax rate of 22% for the first quarter of 2003 compared to an effective tax rate of 11% for the same period last year. The Company continues to invest in qualifying enhanced oil recovery (EOR) projects. However, the anticipated EOR credit in 2003 relative to higher pre-tax income resulting from higher oil prices and increased production resulted in a higher effective tax rate compared to the 2002 period. The Company anticipates an effective tax rate for 2003 below 25%, assuming WTI oil prices stabilize at approximately $26/Bbl.

Liquidity and Capital Resources

Working capital at March 31, 2003 was $6.8 million, up from $5.4 million at March 31, 2002 and up from a negative $3.7 million at December 31, 2002. Net cash provided by operating activities was $8.4 million in the first quarter of 2003, down from $16.5 million in the first quarter of 2002 and down from $15.9 million in the fourth quarter of 2002. The decline from the first quarter of 2002 was due to $3.0 million in capital costs incurred in 2002 but paid in 2003, approximately $1.6 million in additional annual price-based royalty costs on one of the Company's properties and $4.2 million in receivables and other revenue related to electricity sales earned early in 2001 and recovered by the Company in the first quarter of 2002. The payment of the price-based royalty and higher cash outlays related to capital expenditures in the first quarter of 2003 also accounts for the decline in cash flow from operating activities from the fourth quarter of 2002. Uses of funds in the first quarter of 2003 included the payment of the annual price-based royalty of $5.5 million, a total of $4.9 million for capital expenditures and property acquisitions and the payment of $2.2 million in dividends.

On April 8, 2003, the Company's Board of Directors approved a special one-time dividend of $.04 per share, payable May 2, 2003, and a 10% increase in future dividends from $.10 to $.11 per share per quarter.

In the fourth quarter of 2002, the Company's Board of Directors approved the capital budget for 2003 of $27.6 million, which includes the drilling of 98 new wells, of which 13 are horizontal, and 49 well workovers. As of March 31, 2003 five new wells have been drilled, three of which were horizontal. The Company is currently achieving its production targets for 2003 and, assuming stable natural gas and crude oil prices, believes that the implementation of this year's budget will allow the Company to meet its target exit production rate of approximately 17,700 BOE/day.

In the first quarter of 2003, the Company completed the acquisition of a Poso Creek area property in Kern County, California for $2.5 million, which was funded from cash flow from operations. Management estimates that this property includes approximately 2.5 million barrels of proved reserves. In April 2003, the Company entered into a Purchase and Sale Agreement for the acquisition of producing properties and leasehold acreage in the Brundage Canyon field in the Uinta Basin in Utah for approximately $49 million, which is expected to close in the third quarter of 2003. Management estimates the proved reserves for Brundage Canyon at 8.6 million BOE (75% light oil and 25% natural gas).

In 2003, the Company plans to spend approximately $1 million for improvements at its Poso Creek property and may spend up to $15.5 million in Utah to drill up to 26 development, step-out and exploitation wells if that acquisition is closed early enough in 2003. These expenditures will be in

addition to the $27.6 million capital budget. The Company anticipates funding the Brundage Canyon property acquisition and related capital projects from cash generated from operations and borrowings from its credit facility. The Company's current target production rates and cost data do not include the effects of these acquisitions.

Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" With the exception of historical information, the matters discussed in this Form 10-Q are forward-looking statements that involve risks and uncertainties. Although the Company believes that its expectations are based on reasonable assumptions, it can give no assurance that its goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, the timing and extent of changes in commodity prices for oil, gas and electricity, a limited marketplace for electricity sales within California, counterparty risk, competition, environmental risks, litigation uncertainties, drilling, development and operating risks, the availability of drilling rigs and other support services, legislative and/or judicial decisions and other government regulations.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The Company has significant market risk exposure related to the prices received for the sale of its crude oil. A $1 change in oil price per barrel equates to an approximate $5.8 million change in annual revenues. The Company primarily uses zero-cost bracketed collars based on WTI crude oil prices to protect cash flow from a severe crude oil price decline. At March 31, 2003, the Company has hedged 6,500 barrels per day for the remainder of 2003 whereby the Company could capture an average of $3.88 below a WTI price of $22.31 per barrel and may give up to an average of $4.48 above $25.79 per barrel. The Company has also hedged 5,000 barrels per day in the first quarter of 2004 and 4,000 barrels per day for the second through fourth quarters of 2004. In 2004, the Company could capture up to an average of $3.64 per barrel below approximately $22.39 per barrel and may give up to an average of $4.24 per barrel above $25.65 per barrel. In addition to these collars, the Company entered into a series of crude oil swaps based on WTI pricing on 1,500 barrels per day at prices ranging from $25.68 to $27.17 covering the six month period from May 1, 2003 to October 31, 2003 and 1,000 barrels per day for the six months beginning November 2003 for an average price of $25.00. The Company utilizes more than one counterparty on these hedges and monitors each counterparty's credit rating.

The Company is also at risk for a widening of the differential between the WTI crude oil price and the posted price of the Company's heavy crude oil. To minimize this risk, the Company has a sales contract in place through 2005 where more than 90% of its crude oil production is priced at the higher of local field posting plus a bonus, or WTI minus a fixed differential.

The Company also has market risk exposure related to the price received for the sale of its electricity production and the cost paid by the Company for the natural gas used in its cogeneration operations. The Company's three cogeneration facilities, when combined, have electricity production capacity of 98 Mw of electricity. Of this total, the Company sells approximately 92 Mw and the remaining 6 Mw is consumed in the Company's operations. The Company's goal is to control its "spark spread" (the difference between the sales price received for its electricity and the cost to purchase natural gas used as fuel in the cogeneration operations).

The Company consumes approximately 27,000 MMBtu/day of natural gas as fuel in these facilities. A change of $.25/MMBtu in the cost of natural gas used in the cogeneration facilities equates to a change of approximately $1.1 million in annual operating costs. To protect cash flow from future increases in natural gas prices, thereby helping to reduce steam costs, the Company entered into natural gas swaps on a total volume of 5,000 MMBtu per day at a fixed price of $4.85 per MMBtu for the period June 2003 through June 2006. The Company has a long-term electricity sales contract in place, with a major utility, through July 31, 2006 at a fixed price of $53.70/Mwh plus capacity on approximately 19 Mw of electricity production. A change of $1.50/Mwh in the price received for electricity on the remaining 73 Mw equates to approximately $1 million in annual revenues. During 2002, the majority of the remaining electricity was sold on the open market to a creditworthy customer. To protect a portion of the Company's electrical production from low off-peak power prices, the Company entered into a series of fixed price (swap) agreements on 30 Mw of off-peak hour electricity in

August 2002. At March 31, 2003, the Company has two months remaining on the swap agreements in place through May 31, 2003 at $21.00 per Mwh. In January 2003, the Company entered into three reformed or reinstated Standard Offer contracts with the utilities which resulted in improved electrical pricing in the first quarter of 2003 and should also result in improved electrical pricing for the remainder of 2003. These contracts will expire no later than December 31, 2003. The Company is pursuing longer-term arrangements on the sale of electricity and may enter into hedges on its natural gas purchases to seek to improve the spark spread in 2003 and beyond.

The Company also consumes up to an additional 10,000 MMBtu/day of additional natural gas as fuel in its conventional generators, which are used to supplement the Company's steam requirements. A change of $.25 in the cost of this natural gas requirement equates to a change of approximately $.9 million in annual operating costs. The Company may enter into hedges on natural gas purchases to help control this cost or shut-in the conventional generators if deemed appropriate.

Related to its natural gas purchases, the Company is also exposed to the volatility in the differential between gas prices at the Southern California border and Henry Hub delivery points. To help minimize this risk, the Company entered into a 12,000 MMBtu/day firm transportation agreement on the Kern River pipeline expansion for gas deliveries which commenced in May 2003. This agreement provides the Company additional flexibility in securing its natural gas supply and allows the Company to potentially benefit from discounted natural gas prices in the Rockies. This is a 10 year take-or-pay contract and the Company is required to pay approximately $.71/MMBtu if the Company does not take delivery of gas volumes under the agreement. This 10-year take-or-pay commitment totals approximately $31 million over the life of the contract and for 2003 is approximately $2.1 million.

Item 4. Controls and Procedures

The Company's Chief Executive Officer and its Chief Financial Officer have evaluated the Company's disclosure controls and procedures within 90 days of the filing of this report pursuant to Rule 13a-14 of the Securities and Exchange Act of 1934 and have concluded that there are no significant changes in the Company's internal controls or in other factors that could significantly affect these controls.

BERRY PETROLEUM COMPANY
Part II. Other Information

PART II OTHER INFORMATION

Item 6. Exhibits and Reports on Form 8-K

On April 8, 2003, the Company filed a Form 8-K reporting an Item 5 - Other Event to furnish the Securities and Exchange Commission a copy of the Company's press release announcing a dividend increase.

On April 24, 2003, the Company filed a Form 8-K reporting an Item 5 - Other Event to furnish the Securities and Exchange Commission a copy of the Company's press release announcing the Company's intent to acquire certain Uinta Basin properties in Utah.

(a) See Exhibit Index.

SIGNATURES

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 thereunto duly authorized.

BERRY PETROLEUM COMPANY

/s/ Donald A. Dale
Donald A. Dale
Controller
(Principal Accounting Officer)

Date: May 8, 2003

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Jerry V. Hoffman, Chairman, President and Chief Executive Officer of Berry Petroleum Company, certify that:

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant is made known to us by others within the registrant, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors:

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: May 8, 2003

/s/ Jerry V. Hoffman
Jerry V. Hoffman
Chairman, President and
Chief Executive Officer

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Ralph J. Goehring, Senior Vice President and Chief Financial Officer of Berry Petroleum Company, certify that:

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant is made known to us by others within the registrant, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors:

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: May 8, 2003

/s/ Ralph J. Goehring
Ralph J. Goehring
Senior Vice President and
Chief Financial Officer

EXHIBIT INDEX

Exhibit No.

99.1 Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.2 Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Certification of CEO Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report of Berry Petroleum Company (the "Company") on Form 10-Q for the period ending March 31, 2003 as filed with the Securities and Exchange Commission on May 8, 2003 (the "Report"), Jerry V. Hoffman, as Chairman, President and Chief Executive Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge, that:

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

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

A signed original of this written statement has been provided to the Company and will be retained by the Company and furnished to the SEC or its staff upon request.

/s/ Jerry V. Hoffman
Jerry V. Hoffman
Chairman, President and Chief Executive Officer
May 8, 2003

Exhibit 99.1

Certification of CFO Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report of Berry Petroleum Company (the "Company") on Form 10-Q for the period ending March 31, 2003 as filed with the Securities and Exchange Commission on May 8, 2003 (the "Report"), Ralph J. Goehring, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge, that:

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

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

A signed original of this written statement has been provided to the Company and will be retained by the Company and furnished to the SEC or its staff upon request.

/s/ Ralph J. Goehring
Ralph J. Goehring
Senior Vice President and Chief Financial Officer
May 8, 2003