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
For the quarterly period ended September 30, 2005
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 September 30, 2005, was 21,157,155 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
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Part I. Financial Information
Item 1. Financial Statements
CONDENSED BALANCE SHEETS (unaudited)

(In Thousands, Except Per Share Information)		September 30, 2005		December 31, 2005
ASSETS				
Current assets:				
Cash and cash equivalents	$	8,427	$	16,690
Short-term investments available for sale		655		659
Accounts receivable		57,610		34,621
Deferred income taxes		14,094		3,558
Fair value of derivatives		6,623		3,243
Prepaid expenses and other		5,882		2,230
Income taxes receivable		2,177		-
Total current assets		95,468		61,001
Oil and gas properties (successful efforts basis), buildings and equipment, net		512,034		338,706
Deposit on properties		-		10,221
Other assets		5,750		2,176
	$	613,252	$	412,104
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	48,240	$	27,750
Revenue and royalties payable		25,312		23,945
Accrued liabilities		10,921		6,132
Income taxes payable		-		1,067
Fair value of derivatives		37,599		5,947
Total current liabilities		122,072		64,841
Long-term liabilities:				
Deferred income taxes		48,221		47,963
Long-term debt		100,000		28,000
Unearned revenue		995		-
Abandonment obligations		11,221		8,214
Fair value of derivatives		38,713		-
		199,150		84,177
Shareholders' equity:				
Preferred stock, $.01 par value; 2,000,000 shares authorized; 0 outstanding		-		-
Capital stock, $.01 par value;				
Class A Common Stock, 50,000,000 shares authorized; 21,157,155 shares issued and outstanding (21,060,420 in 2004)		212		210
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		58,824		60,676
Accumulated other comprehensive loss		(41,814)		(987)
Retained earnings		274,799		203,178
Total shareholders' equity		292,030		263,086
	$	613,252	$	412,104

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

Part I. Financial Information
Item 1. Financial Statements
CONDENSED INCOME STATEMENTS (unaudited)
Three Month Periods Ended September 30, 2005 and 2004

(In Thousands, Except Per Share Information)	2005	2004
Revenues:		
Sales of oil and gas	$ 96,439	$ 61,560
Sales of electricity	12,933	11,344
Interest and other income, net	612	45
	109,984	72,949
Expenses:		
Operating costs - oil and gas production	28,144	22,487
Operating costs - electricity generation	12,316	10,423
Exploration costs	749	-
Depreciation, depletion and amortization - oil and gas production	8,813	7,500
Depreciation, depletion and amortization - electricity generation	831	823
General and administrative	5,965	4,769
Dry hole, abandonment and impairment	2,803	-
Interest	1,598	512
	61,219	46,514
Income before income taxes	48,765	26,435
Provision for income taxes	14,546	8,206
Net income	$ 34,219	$ 18,229
Basic net income per share	$ 1.55	$ .83
Diluted net income per share	$ 1.52	$ .82
Cash dividends per share	$ .23	$ .18
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share	22,068	21,934
Effect of dilutive securities:		
Stock options	402	375
Other	59	56
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,529	22,365

Condensed Statements of Comprehensive Income (unaudited)
Three Month Periods Ended September 30, 2005 and 2004

(In Thousands)	2005	2004
Net income	$ 34,219	$ 18,229
Unrealized losses on derivatives, (net of income taxes of $11,090 and $4,604 in 2005 and 2004, respectively)	(16,635)	(6,906)
Reclassification of realized losses included in net income (net of income taxes of $2,568 and $490 in 2005 and 2004, respectively)	(3,852)	(736)
Comprehensive income	$ 13,732	$ 10,587

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

Part I. Financial Information
Item 1. Financial Statements
CONDENSED INCOME STATEMENTS (unaudited)
Nine Month Periods Ended September 30, 2005 and 2004

(In Thousands, Except Per Share Information)	2005	2004
Revenues:		
Sales of oil and gas	$ 252,635	$ 159,520
Sales of electricity	36,903	34,569
Interest and other income, net	1,130	338
	290,668	194,427
Expenses:		
Operating costs - oil and gas production	77,925	58,721
Operating costs - electricity generation	36,596	33,415
Exploration costs	1,535	-
Depreciation, depletion and amortization - oil and gas production	26,800	21,497
Depreciation, depletion and amortization - electricity generation	2,443	2,539
General and administrative	15,988	16,956
Dry hole, abandonment and impairment	5,425	-
Interest	4,502	1,577
	171,214	134,705
Income before income taxes	119,454	59,722
Provision for income taxes	37,470	15,850
Net income	$ 81,984	$ 43,872
Basic net income per share	$ 3.72	$ 2.01
Diluted net income per share	$ 3.65	$ 1.97
Cash dividends per share	$ .47	$ .40
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share	22,039	21,875
Effect of dilutive securities:		
Stock options	393	366
Other	57	54
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,489	22,295

Condensed Statements of Comprehensive Income (unaudited)
Nine Month Periods Ended September 30, 2005 and 2004

(In Thousands)	2005	2004
Net income	$ 81,984	$ 43,872
Unrealized losses on derivatives, (net of income taxes of $26,407 and $2,350 in 2005 and 2004, respectively)	(39,611)	(3,525)
Reclassification of realized losses included in net income (net of income taxes of $811 and $1,713 in 2005 and 2004, respectively)	(1,216)	(2,569)
Comprehensive income	$ 41,157	$ 37,778

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

Part I. Financial Information
Item 1. Financial Statements
CONDENSED STATEMENTS OF CASH FLOWS (unaudited)
Nine Month Periods Ended September 30, 2005 and 2004

(In Thousands)	2005	2004
Cash flows from operating activities:		
Net income	$ 81,984	$ 43,872
Depreciation, depletion and amortization	29,243	24,036
Deferred income taxes, net	16,939	6,846
Dry hole, abandonment and impairment	2,298	-
Stock-based compensation expense	404	4,520
Other, net	106	205
Decrease in current assets other than cash, cash equivalents and short-term investments	(28,310)	(12,448)
Increase in current liabilities	19,623	11,451
Net cash provided by operating activities	122,287	78,482
Cash flows from investing activities:		
Capital expenditures, excluding property acquisitions	(78,321)	(51,856)
Property acquisitions	(118,700)	-
Other, net	130	(3,316)
Net cash used in investing activities	(196,891)	(55,172)
Cash flows from financing activities:		
Proceeds from issuance of long-term debt	116,000	-
Payment of long-term debt	(44,000)	(17,000)
Dividends paid	(10,362)	(8,760)
Book overdraft	7,718	-
Repurchase of stock and other	(3,015)	-
Net cash provided by (used in) financing activities	66,341	(25,760)
Net decrease in cash and cash equivalents	(8,263)	(2,450)
Cash and cash equivalents at beginning of year	16,690	10,658
Cash and cash equivalents at end of period	$ 8,427	$ 8,208
Supplemental non-cash activity:		
(Increase) decrease in fair value of derivatives:		
Current (net of income taxes of $11,309 and $4,138 in 2005 and 2004, respectively)	$ 16,964	$ 6,207
Non-current (net of income taxes of $15,909 and ($75) in 2005 and 2004, respectively)	23,863	(113)
Net increase to accumulated other comprehensive loss	$ 40,827	$ 6,094

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

Part I. Financial Information
Item 1. Financial Statements
Notes to Condensed Financial Statements (unaudited)

1. General. All adjustments which are, in the opinion of Management, necessary for a fair statement of Berry Petroleum Company's (the "Company") financial position at September 30, 2005 and December 31, 2004 and results of operations for the three and nine month periods ended September 30, 2005 and 2004 and cash flows for the nine month periods ended September 30, 2005 and 2004 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.

The accompanying unaudited condensed financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2004 financial statements. The December 31, 2004 Form 10-K, March 31, 2005 Form 10-Q and June 30, 2005 Form 10-Q 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. Refer to Note 8 for discussion on the dissolution of subsidiary, Canyon Drilling LLC.

The Company's cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at September 30, 2005 is $7.7 million representing outstanding checks in excess of the bank balance (book overdraft).

2. Fair Value of Derivatives. Due to the increase in NYMEX crude oil futures prices at September 30, 2005 from December 31, 2004 and the addition of the zero-cost collar derivative instruments in June 2005, the Company's net fair value of derivatives liability increased to $69.7 million at September 30, 2005 from $2.7 million at December 31, 2004. The unrealized loss, net of income taxes, of $40.8 million, is recorded in accumulated other comprehensive loss on the Company's balance sheet at September 30, 2005. The deferred tax benefit of the unrealized loss is reflected as an addition to the deferred income tax asset on the Company's balance sheet.

3. Asset Retirement Obligations. The Company follows Statement of Financial Accounting Standard, (SFAS) No. 143, *Accounting for Asset Retirement Obligations*, for recording future site restoration and abandonment costs related to its oil and gas properties. Under SFAS No. 143, the following table summarizes the change in abandonment obligation for the nine months ended September 30 (in thousands):

	2005	2004
Beginning balance at January 1	$ 8,214	$ 7,311
Liabilities incurred	2,963	-
Liabilities settled	(603)	(235)
Accretion expense	647	349
Ending balance at September 30	$ 11,221	$ 7,425

4. Reclassification. Certain amounts in the condensed income statements for the three and nine months ended September 30, 2004 have been reclassified to conform to the 2005 presentation. In the fourth quarter of 2004, the Company concluded that it was appropriate to revise its allocation of cogeneration costs to oil and gas operations. The revised allocation is based on the thermal efficiency (of fuel in generating electricity and producing steam) of the Company's cogeneration facilities. In addition, in 2005 the Company is reclassifying technical labor between general and administrative expenses and operating costs - oil and gas. These reclassifications had no impact on net income or net cash provided by operating activities. Accordingly, the Company has revised prior classifications for the three and nine months ended September 30, 2004 as follows (in thousands):

	Three Months Ended 9/30/04	Nine Months Ended 9/30/04
Operating costs - oil and gas		
As previously reported	$ 22,107	$ 59,321
As revised	22,487	58,721
Difference	$ (380)	$ 600
Operating costs - electricity generation		
As previously reported	$ 11,344	$ 34,569
As revised	10,423	33,415
Difference	$ 921	$ 1,154
G&A expenses		
As previously reported	$ 4,228	$ 15,202
As revised	4,769	16,956
Difference	$ (541)	$ (1,754)
DD&A - oil and gas		
As previously reported	$ 8,323	$ 24,036
As revised	7,500	21,497
Difference	$ 823	$ 2,539
DD&A - electricity generation		
As previously reported	$ -	$ -
As revised	823	2,539
Difference	$ (823)	$ (2,539)

5. Credit Facility. In June 2005 the Company completed a new unsecured five-year bank credit agreement (the Agreement) with a banking syndicate. The Agreement is a revolving credit facility for up to $500 million with nine banks and replaces the previous $200 million facility which was due to mature in 2006. Initial borrowings were $125 million which represented an amount equal to the borrowings outstanding under the previous credit facility and the initial borrowing base was established at $350 million. This transaction is considered a modification of a debt instrument due to modification of terms in accordance with Emerging Issues Task Force, (EITF) 96-19, *Debtor's Accounting for Modification or Exchange of Debt Instruments*.

The total outstanding debt on the $350 million credit facility available was $100 million at September 30, 2005. The Agreement matures on July 1, 2010. Interest on amounts borrowed is charged at LIBOR plus a margin or the prime rate, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. The Company is required under the Agreement to pay a commitment fee of 25 to 38 basis points on the unused portion of the credit facility.

The weighted average interest rate on outstanding borrowings at September 30, 2005 was 4.8%. The Company was in compliance with all covenants as of September 30, 2005.

6. Dry hole, abandonment and impairment. The majority of the $2.8 million reflected on the Company's income statement under dry hole, abandonment and impairment is the write off of the remaining carrying value of its Illinois and Eastern Kansas prospective coal bed methane (CBM) acreage acquired in 2002. Due to lack of regional activity for evaluation and/or development of similar prospective CBM acreage and the inability to attract buyers, the Company determined the assets were impaired in the third quarter of 2005.

7. Pro Forma Results. On January 27, 2005, the Company acquired certain interests in the Niobrara field in northeastern Colorado for approximately $105 million (J-W Acquisition). The unaudited pro forma results presented below for the nine months ended September 30, 2005 and 2004 have been prepared to give effect to the J-W Acquisition on the Company's results of operations under the purchase method of accounting as if it had been consummated on January 1, 2004. The unaudited pro forma results do not purport to represent the results of operations that actually would have occurred on such date or to project the Company's results of operations for any future date or period. (in thousands, except per share data):

	2005	2004
Proforma Revenue	$ 292,031	$ 208,852
Proforma Income from operations	140,611	84,872
Proforma Net income	82,288	45,863
Proforma Basic earnings per share	3.73	2.10
Proforma Diluted earnings per share	3.66	2.06

8. Canyon Drilling. Canyon Drilling LLC ("Canyon"), a 100% owned Colorado entity, was dissolved in the third quarter of 2005. Canyon owned a drilling rig which was leased to a third party. After the dissolution, the drilling rig is 100% owned by the Company. Concurrent with the dissolution of Canyon, the original lease was terminated and a revised three year lease agreement was executed which has similar terms to the original lease. The revised lease includes a three year purchase option. The total net investment in the revised lease is approximately $3.4 million and is accounted for as a direct financing lease as defined by SFAS No. 13, *Accounting for Leases*. Net investment in this lease as of September 30, 2005 is as follows (in thousands):

Net minimum lease payments receivable	$ 4,854
Unearned income	(1,489)
Net investment in direct financing lease	$ 3,365

Estimated future minimum lease payments, including the purchase option, to be received as of September 30, 2005 are as follows (in thousands):

2005	$ 126
2006	504
2007	504
2008	3,720
Total	$ 4,854

9. Taxes. The Company's effective tax rate was 30% for the third quarter of 2005 compared to 32% for the second quarter of 2005 and 31% for the third quarter of 2004. The Company benefits from enhanced oil recovery (EOR) credits on development activities on its heavy oil properties which reduces the Company's income tax liabilities and accordingly, the effective tax rate in 2005. EOR credits are expected to be fully phased out in 2006 due to the high level of crude oil prices in 2005.

10. Recent Accounting Pronouncements. In December 2004, SFAS No. 123 (revised 2004) or SFAS No. 123(R), Share-Based Payment was issued. This statement requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at their fair value on the grant date. SFAS No. 123(R) is effective as of the beginning of the first annual reporting period that begins after June 15, 2005. As a result, the Company expects to adopt this statement on January 1, 2006. The adoption of this statement is not expected to have a material impact on the Company's financial position, net income or cash flows.

In March 2005, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"). FIN 47 clarifies the definition and treatment of conditional asset retirement obligations as discussed in FASB Statement No. 143, Accounting for Asset Retirement Obligations. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the company. FIN 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. FIN 47 is intended to provide more information about long-lived assets and future cash outflows for these obligations and more consistent recognition of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. The adoption of FIN 47 is not expected to have a material impact on the Company's financial position, net income or cash flows.

11. Subsequent Events. In October 2005 the following three events took place. The Company entered into a three-year drilling contract for the services of an automated drilling rig. The three year drilling contract begins upon delivery of the rig which is expected in second quarter of 2006. Secondly, the Company purchased a drilling rig which is being refurbished in preparation for leasing to a drilling company. Lastly, the Company purchased a 50% interest in approximately 70,000 gross undeveloped acres (60,000 net) in Colorado's Phillips and Sedgwick Counties. This additional Niobrara leasehold position is adjacent to and immediately north of Berry's producing natural gas assets in Yuma County. The Company is scheduled to begin shooting a 3-D seismic survey within the next three months and expects to drill the first delineation wells in mid-2006.

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

Company Overview

The following discussion provides information on the results of operations for each of the three and nine month periods ended September 30, 2005 and 2004 and the financial condition, liquidity and capital resources as of September 30, 2005. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

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

Corporate Strategy

The Company's mission is to increase shareholder value, primarily through maximizing the value and cash flows of the Company's assets. The strategies to accomplish these goals include:

- Growing production and reserves from existing assets while managing expenses
- Acquiring more light oil and natural gas assets with significant growth potential in the Rockies and Mid-Continent
- Utilizing joint ventures with respected partners to enter new basins
- Investing the Company’s capital in an efficient, disciplined manner to increase production and reserves
- Appraising the Company’s exploitation and exploration projects in an expedient manner

Key Third Quarter Items

- Achieved record production which averaged 23,647 BOE/D
- Increased 2005 capital budget from $107 million to $136 million
- Added approximately 13,000 net acres in the North Dakota Bakken play
- Increased quarterly dividend to $.13 per share and paid special dividend of $.10 per share
- Paid down $25 million in debt
- Began 25 well expansion of California Diatomite project
- Began drilling to assess several prospects
- Repurchased shares for $2.6 million
- Wrote off Eastern Kansas and Illinois properties

Anticipated and Completed Key Fourth Quarter Items

- Continuing to grow production
- Will obtain initial data on several key appraisal wells
- Negotiating crude oil sales contract for California production
- Added approximately 60,000 net acres to Colorado Niobrara inventory
- Executed three-year contract for automated drilling rig in California
- Realigned organization into asset teams
- Added Joseph H. Bryant to the Board of Directors in October 2005

Results of Operations

	Three Months Ended				
	Sep 30, 2005	Sep 30, 2004	Change	Jun 30, 2005	Change
Revenues (in millions)	$ 110.0	$ 72.9	51%	$ 92.7	19%
Net Income (in millions)	34.2	18.2	88%	25.3	35%
Earnings per share (diluted)	1.52	0.82	85%	1.13	35%

Oil and Gas Sales and Production. The Company’s revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. Improvements in production volume are due to acquisitions and sizable capital investments. Improvement in prices during 2005 are due to a tighter supply and demand balance and the nervousness of the market about possible supply disruptions. In 2005, the Company anticipates production to average approximately 23,000 BOE/D. Production in 2006, excluding acquisitions, is expected to average approximately 25,000 BOE/D.

The following table presents certain oil and gas operating data for the periods ending:

	Three Months Ended						Nine Months Ended	
	Sept 30, 2005	%	Jun 30, 2005	%	Sept 30, 2004	%	Sept 30, 2005	Sept 30, 2004
Oil and Gas								
Heavy Oil Production (Bbl/D)	16,701	71	15,733	70	15,626	75	16,086	15,807
Light Oil Production (Bbl/D)	3,308	14	3,253	14	3,689	18	3,301	3,219
Total Oil Production (Bbl/D)	20,009	85	18,986	84	19,315	93	19,387	19,026
Natural Gas Production (Mcf/D)	21,829	15	22,090	16	9,066	7	20,438	7,302
Total (BOE/D)	23,647	100	22,668	100	20,825	100	22,793	20,243
Per BOE:								
Average sales price before hedging	$ 51.34		$ 43.41		$ 35.61		$ 45.38	$ 31.58
Average sales price after hedging	44.25		39.09		32.28		40.48	28.81
Oil, per Bbl:								
Average WTI price	$ 63.31		$ 53.22		$ 43.88		$ 55.61	$ 39.21
Price sensitive royalties	(5.68)		(3.76)		(3.38)		(4.22)	(2.78)
Gravity differential	(4.94)		(5.47)		(4.91)		(5.18)	(4.93)
Crude oil hedges	(8.35)		(5.27)		(3.59)		(5.78)	(2.93)
Average oil sales price after hedging	$ 44.34		$ 38.72		$ 32.00		$ 40.43	$ 28.57
Gas, per MMBtu:								
Average Henry Hub price	$ 6.97		$ 6.70		$ 5.76		$ 6.62	$ 5.81
Natural gas hedges	0.02		(0.04)		-		(0.02)	(0.01)
Location and quality differentials	(0.85)		(0.87)		(0.69)		(0.78)	(0.61)
Average gas sales price after hedging	$ 6.14		$ 5.79		$ 5.07		$ 5.82	$ 5.19

California Oil and Gas Sales Contract. The Company sells the majority of its California heavy crude oil under a favorable contract which expires on December 31, 2005. The contract pricing is based upon the higher of the average of 1) the local field posted prices plus a fixed premium, or 2) WTI minus a fixed amount of approximately $6 per barrel. The Company is in negotiations on a multi-year contract for its California heavy crude oil. The Company believes it can achieve fair contract terms based on the significant daily quantity of crude oil it can deliver. In 2006, the Company expects that its oil revenues will be negatively impacted as the new contract terms will likely be less favorable than the existing contract due to the widening of the crude price differential between WTI and California heavy crude. The differential, which over the last several years approximated $6 per barrel, increased dramatically in the second half of 2004 to approximately $14 per barrel. The differential narrowed to approximately $10.50 per barrel as of September 30, 2005.

In the third quarter of 2005, the Company estimates that its revenues benefited from the existing contract by approximately $8.1 million. At a differential of approximately $12.75 per barrel for the first nine months of 2005, the Company estimates that its revenues will benefit from the contract by approximately $42.6 million in 2005. While Management believes that the differential will narrow and move closer toward its historical level over time, there are no assurances that this will occur.

Hedging Revenue. As a result of hedging activities the Company's revenue, which was reported in Sales of oil and gas in the financial statements, was reduced by $30.6 million and $15.3 million in the nine months ended September 30, 2005 and 2004, respectively. These hedging activities resulted in a net reduction in revenue per BOE to the Company of $7.09 in the third quarter of 2005, $4.32 in the second quarter of 2005 and $3.33 in the third quarter of 2004. As of September 30, 2005, hedging contracts had settlement dates through the end of 2009 and no ineffectiveness was realized. If the differential were to change significantly, it is possible that the Company’s hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to the Company’s sales and net income. See Note 2 to the unaudited condensed financial statements and “Item 3. Quantitative and Qualitative Disclosure About Market Risk.”

Electricity. The Company consumes natural gas as fuel to operate its three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the economic production of heavy oil. The Company sells its electricity to utilities under Standard Offer contracts, under which its revenues are linked to the cost of natural gas. Natural gas index prices are the primary determinant of the Company's electricity sales price. The correlation between electricity sales and natural gas prices allows the Company to more effectively manage its cost of producing steam. Electricity production was lower in the second quarter of 2005 due to a scheduled turnaround, which included a turbine refurbishment. Revenue and operating costs in the third quarter of 2005 were up from the second quarter of 2005 due to 14% higher electricity prices and 16% higher natural gas prices, respectively. The Company purchased approximately 25,400 MMBtu/D as fuel for use in its cogeneration facilities in the nine months ended September 30, 2005.

	Three Months Ended			Nine Months Ended	
	Sept 30, 2005	Jun 30, 2005	Sept 30, 2004	Sept 30, 2005	Sept 30, 2004
Electricity					
Revenues (in millions)	$ 12.9	$ 11.5	$ 11.3	$ 36.9	$ 34.6
Operating Costs (in millions)	$ 12.3	$ 10.9	$ 10.4	$ 36.6	$ 33.4
Electric power produced (MWh/D)	2,025	1,897	2,122	2,013	2,112
Electric power sold (MWh/D)	1,830	1,702	1,916	1,816	1,905
Average sales price/MWh	$ 84.89	$ 74.52	$ 75.96	$ 76.08	$ 70.25
Fuel gas cost/MMBtu (excluding transportation)	$ 7.16	$ 6.15	$ 5.27	$ 6.34	$ 5.27

Oil and Gas Operating, G&A and Interest Expenses. The following table presents information comparing the Company's oil and gas operating expenses for each of the quarters ended September 30, 2005 and 2004 and June 30, 2005:

Three Months Ended:	per BOE					in thousands		
	Sep 30, 2005	Jun 30, 2005	Change	Sep 30, 2004	Change	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004
Operating costs	$ 12.94	$ 12.79	1%	$ 11.74	10%	$ 28,144	$ 26,374	$ 22,487
DD&A	4.05	4.59	(12%)	3.91	4%	8,813	9,461	7,500
G&A	2.74	2.52	9%	2.49	10%	5,965	5,204	4,769
Interest expense	0.73	0.84	(13%)	0.27	170%	1,598	1,740	512

- Higher crude oil and natural gas prices have created an incentive for the U.S. domestic oil and gas industry to significantly increase exploration and development activities which is straining the capacity for such goods and services. Thus, higher costs are prominent throughout the industry and resulted in higher operating costs per BOE for the third quarter of 2005 from the third quarter of 2004. The cost of the Company's steaming operations on its heavy oil properties represents a significant portion of the Company's operating costs and will vary depending on the cost of natural gas used as fuel and the volume of steam injected. The following table presents this information:

	Three Months Ended			Nine Months Ended		
	Sep 30, 2005	Sep 30, 2004	Change	Sep 30, 2005	Sep 30, 2004	Change
Volume of steam injected (Bbl/D)	69,590	72,556	(4%)	69,362	67,889	2%
Fuel gas cost/MMBtu	$ 7.16	$ 5.27	36%	$ 6.34	$ 5.27	20%

- DD&A increased per BOE in the third quarter of 2005 from the third quarter of 2004 due to higher acquisition costs of the Company's Rockies and Mid-Continent assets as compared to the Company's legacy heavy oil assets in California and higher finding and development costs.

- Approximately two-thirds of the Company's G&A is compensation or compensation related costs. The Company intends to remain competitive in workforce compensation to achieve its growth plans. The third quarter 2005 increase compared to third quarter 2004 is due to higher compensation as well as hiring an additional 55 employees for a total of 211 employees as of September 30, 2005.

- Interest expense in the third quarter of 2005 per BOE was up from the third quarter of 2004 due to increased outstanding borrowings of $100 million at September 30, 2005 as compared to $33 million at September 30, 2004 Average borrowings increased as a result of acquisitions of $119 million in the first nine months of 2005. Additionally, interest rates have increased by approximately 2% since September 30, 2004.

The following table presents information comparing the Company’s operating expenses for the nine months ended September 30, 2005 and 2004:

Nine Months Ended:	per BOE			in thousands	
	Sep 30, 2005	Sep 30, 2004	Change	Sep 30, 2005	Sep 30, 2004
Operating costs	$ 12.52	$ 10.59	18%	$ 77,925	$ 58,721
DD&A	4.31	3.88	11%	26,800	21,497
G&A	2.57	3.06	(16%)	15,988	16,956
Interest expense	0.72	0.28	157%	4,502	1,577

Also see the three month variance explanations, as the variances in the nine month periods do not differ significantly from the three month variance discussion on the previous page, with the exception of G&A.

- The Company anticipates operating costs to average between $13.75 and $14.25 per BOE for 2005 based on Henry Hub (HH) $13.30 per MMBtu gas price in the fourth quarter, while the average gas price for all of 2005 is estimated to be approximately $9.00 per MMBtu. Based on HH natural gas prices of approximately $10.00 per MMBtu in 2006, the Company projects its 2006 operating costs would average between $16.00 and $17.00 per BOE. Higher operating costs for 2006 are anticipated due to increases in all of the following; gas prices, steam volumes, well service costs, other contractual costs, labor and production taxes.

- The Company anticipates DD&A will average between $4.25 and $4.75 per BOE for 2005 and between $5.00 and $6.00 per BOE for 2006.

- G&A expenses per BOE in the first nine months of 2005 decreased from the first nine months of 2004 due to the charge on stock options that was part of the Company’s change in accounting method in 2004. The Company expects G&A will average between $2.55 and $2.65 per BOE for all of 2005 and between $2.40 and $2.80 per BOE in 2006.

- The Company anticipates interest expense to be between $.60 to $.80 per BOE for 2005 and between $.50 to $.75 per BOE for 2006.

Income Taxes. See Note 9 to the unaudited condensed financial statements. The Company benefits from EOR credits on development activities on its heavy oil properties. However, with higher crude oil prices and the increasing investment in its light crude oil and natural gas properties, the Company’s effective income tax rate is trending higher compared to prior years. Based on current forecasted oil prices, the Company anticipates an effective tax rate for all of 2005 between 31% and 33%. The Company estimates that the average U.S. wellhead price for crude oil will exceed $43 in 2005, thus triggering a full phase-out of the EOR credit for 2006. Without any EOR credit in 2006, the Company anticipates its effective tax rate will be between 37% and 39%. If the U.S. wellhead price of crude oil declines below the triggering point, in future years the Company will be able to claim the EOR credit on qualifying expenditures and the Company’s effective tax rate should decline.

Dry Hole, Abandonment and Impairment. See Note 6 to the unaudited condensed financial statements.

Acquisitions During and Subsequent to the Quarter. In the third quarter, Berry completed several transactions whereby Berry now has total working interests in over 33,000 net acres (160,000 gross) located in the Williston Basin in North Dakota. These acquisitions, totaling approximately $9 million, provide the Company an entry into the emerging Bakken oil play in the Williston Basin. The acreage covers several contiguous blocks located primarily on the eastern flank of the Nesson Anticline.

Development activity in the Middle Bakken play is generally expanding to the area surrounding the Nesson Anticline. Closing on additional acreage is anticipated in fourth quarter 2005.

In October 2005, the Company purchased a 50% interest in approximately 70,000 gross undeveloped acres (60,000 net) in Colorado's Phillips and Sedgwick Counties. This additional Niobrara leasehold position is adjacent to and immediately north of Berry's producing natural gas assets in Yuma County. The Company is scheduled to begin shooting a 3-D seismic survey within the next three months and expects to drill the first delineation wells in mid-2006.

California Diatomite Exploitation. Oil production from the initial 14 well pilot (6 producers), which averaged approximately 220 Bbl/D in the third quarter of 2005, is economic at current oil prices. The Company is continuing to assess the long-term economic and operating viability of the project as the pilot is an indication of future large-scale development. Results continue to be encouraging. The Company is judiciously monitoring the steam to oil ratio (SOR) because the Company believes achieving an SOR of 6 or less is the threshold for commerciality. Due to positive results thus far, the Company began an expansion of the pilot with a 25 well program (15 producers) in the third quarter. Additionally, the Company is preparing for a much larger expansion in 2006 with up to 50 wells (31 producers) and related facilities for a capital investment approximating $25 million. Estimated original oil in place ranges between 200 million to 250 million barrels with the Company targeting a minimum 25% recovery of original oil in place. The Company believes that the project continues to remain on track towards commerciality.

Other Exploration Activities. The Company has a working interest in approximately 390,000 gross (172,250 net) prospective acres, located in eastern Colorado, western Kansas and southwestern Nebraska. The Company and its joint venture partner, collectively "the JV", will jointly explore and develop shallow Niobrara biogenic natural gas, Sharon Springs Shale gas and deeper Pennsylvanian formation oil potential on the acreage. The JV's first exploratory wells at Prairie Star are commercial and the JV is proceeding with two 35 mile 3-D seismic data surveys on nearby acreage. Additionally, the JV intends to drill another five wells at Prairie Star in the fourth quarter of 2005.

In the Uinta Basin Coyote Flats prospect, the Company is drilling an exploratory well into the Ferron sands. The Company will drill a six-well CBM program on this prospect in 2005 and 2006.

Also in the Uinta Basin, the Company has two shallow Green River oil and gas wells scheduled for drilling on its Lake Canyon acreage during the fourth quarter of 2005. These initial wells will be approximately three miles west of the Company's Brundage Canyon field. In an attempt to define deeper horizons, a 57 square mile 3-D seismic survey at Lake Canyon was completed and the results are being interpreted and evaluated. In October 2005, the Company and its partner began drilling a deep Mesaverde gas test well that is expected to reach targeted depth of 14,200 feet before year end.

The Company has a minority interest in two other exploratory wells which are being tested and evaluated; one in the North Dakota Bakken oil play, and the second well is targeting deep Mesaverde gas in a unit southeast of the Brundage Canyon field in the Uinta Basin.

Update to Drilling Activities. The following table is in net wells:

	2005 Budget		Nine Months Ended September 30, 2005	
Location	# New Wells	# Workovers	# New Wells	# Workovers
California	69	83	44	45
Mid-Continent				
Niobrara	64	19	41	55
Bakken	1	-	-	-
Tri-State	4	-	-	-
Rockies				
Brundage Canyon	59	39	45	25
Lake Canyon	1	-	-	-
Coyote Flats	5	1	-	-
Total	203	142	130	125

California Drilling Rigs. The Company entered into a three-year drilling contract for the services of an automated drilling rig. This rig provides a means for Berry to meet at least half of its California new well drilling needs for the next three years, with the other half being met by conventional drilling rigs. The three year drilling contract begins upon delivery of the rig which is expected in second quarter of 2006.

Rockies and Mid-Continent Drilling Rigs. During 2005, the Company purchased two drilling rigs. The first rig is leased to a drilling company under a three year contract, while the second rig is currently being refurbished in preparation for leasing under a similar drilling contract. Owning these rigs allows the Company to successfully meet the majority of its drilling needs in the Uinta Basin over the next several years.

Organization Realignment. In October 2005, the Company modified its management structure to better align the organization with its growth and diversification strategies. Over the last two years the Company has successfully added significant producing assets and prospective acreage in the Rockies and Mid-Continent. The new organizational structure will utilize integrated asset teams, and accordingly, several officers were promoted or had their responsibilities realigned with the Company’s objectives.

Financial Condition, Liquidity and Capital Resources

Capital Budget. The Company establishes a capital budget for each calendar year based on its development opportunities and the expected cash flow from operations for that year. Excess cash generated from operations is expected to be applied toward acquisitions, debt reduction or other corporate purposes. The Company has re-evaluated its current capital budget of $107 million and authorized a $29 million increase for the remainder of 2005 to $136 million in light of current crude oil and natural gas prices and the Company’s significant opportunities. All capital expenditures, excluding acquisitions, will be funded out of internally generated cash flow.

The $29 million increase in the 2005 budget will be directed at 1) additional wells and workovers in California, 2) additional wells in the Uinta Basin, 3) participation in wells in the Bakken play in North

Dakota, and 4) various facilities, seismic surveys and other items. Berry is confident that it can obtain the rigs and services over the next few months to fulfill this additional work program. The goal is to reinvest a portion of the Company’s excellent cash flow into high rate of return projects and to accelerate the assessment process on some of the Company’s prospective acreage. In 2006, the Company anticipates the capital program will be at least $150 million.

Dividends. The regular quarterly dividend was increased by 8%, from $.12 to $.13 per share, beginning with the September 2005 dividend. The total dividend payable on September 29, 2005 was $.23 per share which included a special $.10 per share dividend. This is the third consecutive year that the Company has raised its quarterly dividend and distributed a special dividend. This action should result in a total payout in 2005 of $.60 per share, up 15% from the $.52 per share paid out in 2004.

Working Capital and Cash Flows. Cash flow from operations is dependent upon the price of crude oil and natural gas and the Company's ability to increase production and manage costs. Prices and sales have increased in the first nine months of 2005 due to increase in real and perceived world supply shortages and increase in the market demand for oil and gas, while production has increased due to acquisitions and improved finding and development technology.

The Company's working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under its credit arrangements. The Company increased the borrowings on its credit line primarily to fund property acquisitions. Generally, the Company uses excess cash to pay down borrowings under its credit arrangement. As a result, the Company often has a working capital deficit or a relatively small amount of positive working capital. See table below for further information:

	Nine Months Ended		
	Sep 30, 2005	Sep 30, 2004	Change
Net cash provided by operating activities (in millions)	$ 122.3	$ 78.5	56%
Production (BOE/D)	22,793	20,243	13%
Average oil and gas prices, net of hedging	$ 40.48	$ 28.81	41%
Sales of oil and gas (in millions)	252.6	159.5	58%
Working capital (in millions)-end of period	(26.6)	(3.8)	(600%)
Long-term debt (in millions)-end of period	100.0	33.0	203%
Property acquisitions and deposits on acquistions (in millions)	118.7	3.3	3,497%
Dividends paid (in millions)	10.4	8.8	18%

In June 2005, a share repurchase program was authorized for up to an aggregate of $50 million of the Company's outstanding Class A Common Stock. Through September 30, 2005 the Company had repurchased 43,900 shares for approximately $2.6 million.

Contractual Obligations. The Company's contractual obligations as of September 30, 2005 are as follows (in thousands):

	Total	1 Year or less	Years 2 and 3	Years 4 and 5	More than 5 years
Long-term debt (1)	$ 100,000	$ -	$ -	$ 100,000	$ -
Abandonment obligations	11,221	315	899	1,113	8,894
Other obligations, including buildings	1,369	621	676	72	-
Drilling and rig obligation	15,830	6,230	4,250	5,350	-
Firm natural gas transportation contract	21,334	2,814	5,628	5,628	7,264
Total	$ 149,754	$ 9,980	$ 11,453	$ 112,163	$ 16,158

(1) Long-term debt does not include interest as the balance can be paid before its maturity date without significant penalty.

Hedging. See Note 2 to the unaudited condensed financial statements and "Item 3. Quantitative and Qualitative Disclosure About Market Risk."

Credit Facility. See Note 5 to the unaudited condensed financial statements. The new credit facility, which has an initial borrowing base of $350 million, is an integral part of the Company's financing structure that provides improved access to capital and the flexibility to support growth plans.

Part I. Financial Information
Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 2 to the unaudited condensed financial statements and in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations," to minimize the effect of a downturn in oil and gas prices and protect the profitability of the Company and the economics of the Company's development plans, from time to time the Company enters into crude oil and natural gas hedge contracts. The terms of contracts depend on various factors, including Management's view of future crude oil and natural gas prices and the Company's future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil price downturn while allowing Berry to participate in the upside. Management regularly monitors the crude oil and natural gas markets and the Company's financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging or other price protection is appropriate in accordance with Board established policy.

Currently, the Company's hedges are in the form of swaps and collars. However, the Company may use a variety of hedge instruments in the future to hedge WTI or the index gas price. The Company has crude oil sales contracts in place, which are priced based on a correlation to WTI. Natural gas (for cogeneration and conventional steaming operations) is purchased at the Socal border price and the Company sells its produced gas in Colorado and Utah at the Colorado Interstate Gas (CIG) and Questar index prices, respectively.

The following table summarizes the hedge position of the Company as of September 30, 2005:

Term	Average Barrels Per Day	Average Price
Crude Oil Sales (NYMEX WTI)		
Swaps		
4th Quarter 2005	7,500	$ 40.75
1st Quarter 2006	3,000	$ 50.91
2nd Quarter 2006	3,000	$ 50.17
3rd Quarter 2006	3,000	$ 49.56
Collars		Floor / Ceiling Prices
1st through 3rd Quarter 2006	7,000	$47.50 / $70
4th Quarter 2006	10,000	$47.50 / $70
Full year 2007	10,000	$47.50 / $70
Full year 2008	10,000	$47.50 / $70
Full year 2009	10,000	$47.50 / $70

Term	Average MMbtu Per Day	Average Price
Natural Gas Sales (CIG)		
Swaps		
4th Quarter 2005	5,000	$ 6.76
1st Quarter 2006	3,000	$ 7.49
Natural Gas Purchases (SoCal Border)		
Swaps		
4th Quarter 2005	6,000	$ 5.05
1st Quarter 2006	5,000	$ 4.85
2nd Quarter 2006	5,000	$ 4.85

The collar strike prices will allow the Company to protect a significant portion of its future cash flow if oil prices decline below $47.50 per barrel while still participating in any oil price increase up to $70 per barrel on these volumes. These hedges improve the Company's financial flexibility by locking in significant revenues and cash flow upon a substantial decline in crude oil prices. It also allows the Company to develop its long-lived assets and pursue exploitation opportunities with greater confidence in the projected economic outcomes.

The Company's California oil production is heavy crude that, for the remainder of 2005, is sold to a refiner under a favorable sales contract to Berry. As of September 30, 2005, California heavy crude oil sold at a discount of approximately $10.50 per barrel to WTI and at this time the Company is retaining the risk of movement in this price differential on its production beginning in 2006. While the Company has designated its hedges as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, it is possible that a portion of the hedge related to the movement in the WTI to California heavy oil price differential may be determined to be ineffective. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income. While Management believes that the differential will narrow and move closer toward its historical level over time, there are no assurances as to the movement in the differential. If the differential were to change significantly, it is possible that the Company's hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to the Company's net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity. Irrespective of the unrealized gains reflected in Other Comprehensive Income, the ultimate impact to net income over the life of the hedges will reflect the actual settlement values.

At September 30, 2005, Accumulated Other Comprehensive Loss, net of income taxes, consisted of $41.8 million of unrealized losses from the Company's crude oil and natural gas hedges. Deferred net losses recorded in Accumulated Other Comprehensive Loss at September 30, 2005 are expected to be reclassified to earnings through 2006 for the Company's swaps and at current prices the Company's collars are not expected to impact earnings.

The use of hedging transactions may involve basis risk. The Company's oil hedges are based on reported settlement prices on the NYMEX. The basis risk between NYMEX and the Company's California heavy crude oil is mitigated by the Company's crude oil sales contracts. Pricing in the existing California agreement is based upon the higher of the average of 1) the local field posted prices plus a fixed premium, or 2) WTI minus a fixed amount of approximately $6 per barrel. This contract expires on December 31, 2005. The Company is in negotiations on a multi-year contract for its California heavy crude oil. Pricing in the existing crude oil sales agreement at Brundage Canyon is based upon average weekly WTI minus a fixed differential of approximately $2 per barrel through September 30, 2006. After contract expiration, and absent any new contracts, prices will be negotiated based on the market. Upon the expiration of these crude oil contracts, and absent any new contracts, the Company will be exposed to fluctuations in the basis differentials between WTI and the posted price for its crude oil at its various producing locations until new contracts which lock in such differential can be obtained.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to the Company's hedging activities, the Company utilizes multiple counterparties on its hedges and monitors each counterparty's credit rating.

Based on NYMEX futures prices as of September 30, 2005, (WTI $64.27; HH $13.09) and due to the backwardated nature of the futures prices as of that date, the Company would expect to make pre-tax future cash payments or to receive payments over the remaining term of its crude oil and natural gas hedges in place as follows:

	Sep 30, 2005 NYMEX Futures	Impact of percent change in futures prices on earnings			
		-20%	-10%	+10%	+20%
Average WTI Price	$ 64.27	$ 51.41	$ 57.84	$ 70.69	$ 77.12
Crude oil loss (in millions)	(32)	(11)	(21)	(56)	(145)
Average HH Price	13.09	10.47	11.78	14.40	15.71
Natural gas gain (in millions)	7	5	6	7	8
Net pre-tax future cash (payments) and receipts by year (in millions):					
2005	$ (16)	$ (7)	$ (11)	$ (21)	$ (25)
2006	(9)	1	(4)	(23)	(47)
2007	-	-	-	(5)	(29)
2008	-	-	-	-	(21)
2009	-	-	-	-	(15)
Total	$ (25)	$ (6)	$ (15)	$ (49)	$ (137)

The Company's exposure to changes in interest rates results primarily from long-term debt. Total debt outstanding was $100 million and $33 million, at September 30, 2005 and 2004, respectively. Interest on amounts borrowed is charged at LIBOR plus a margin or the prime rate, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. Based on these borrowings, a 1% change in interest rates would not have a material impact on the Company's financial statements.

Part I. Financial Information
Item 4. Controls and Procedures

As of September 30, 2005, the Company has carried out an evaluation under the supervision of, and with the participation of, the Company’s Management, including the Company’s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company’s disclosure controls and procedures pursuant to Rule 13a-15 under the Securities and Exchange Act of 1934, as amended.

Based on their evaluation as of September 30, 2005, the Chief Executive Officer and Chief Financial Officer of the Company have concluded that the Company’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There was no change in the Company's internal control over financial reporting during the most recently completed calendar quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Commonly Used Oil and Gas Terms

Bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or condensate.

BOE Barrel of oil equivalent, measured as 6 thousand cubic feet of natural gas equal to 1 barrel of crude oil.

CBM Coal bed methane.

HH Henry Hub. The pipeline interchange and the delivery point for the NYMEX active natural gas futures market.

MMBtu Million British thermal units. A British thermal unit represents the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Mcf One thousand cubic feet.

MWh Megawatt hour. One million watts generated per hour.

Net When used in conjunction with wells and acreage indicates the sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NYMEX New York Mercantile Exchange.

WTI West Texas Intermediate. The US benchmark crude oil, approximating 40 degree API gravity.

/D per day.

Forward Looking Statements

Safe harbor under the “Private Securities Litigation Reform Act of 1995” Any statements in this Form 10-Q that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as “strategy,”“anticipates,””possible,”“estimates,” "believes," "should," "plans," "may," "can," "will," "expects," "potential,” "target" and others indicate forward-looking statements, but their absence does not mean that a statement is not forward-looking, if the discussion involves strategy, beliefs, plans, targets, or intentions.

Forward-looking statements are made based on Management’s current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. Important factors which could affect actual results are discussed in Part II of the Company’s Form 10-K filed with the Securities and Exchange Commission, under the heading "Other Factors Affecting the Company's Business and Financial Results" in the section titled "Management’s Discussion and Analysis of Financial Condition and Results of Operations."

Part II. Other Information

Item 1. Legal proceedings
None
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
None
Item 3. Defaults Upon Senior Securities
None
Item 4. Submission of Matters to a Vote of Security Holders
None
Item 5. Other Information
None

Item 6. Exhibits

Exhibit No.	Description of Exhibit
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. *

* Filed herewith

SIGNATURE

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

BERRY PETROLEUM COMPANY

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

Date: November 3, 2005

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert F. Heinemann, 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 (the “Company”);

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

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

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

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

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

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

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

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

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

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

Date: November 3, 2005 /s/ Robert F. Heinemann
Robert F. Heinemann
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Ralph J. Goehring, Executive 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 (the “Company”);

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

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

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

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

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

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

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

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

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

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

Date: November 3, 2005

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

Exhibit 32.1
Certification of Chief Executive Officer 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 September 30, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report").

I, Robert F. Heinemann, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Robert F. Heinemann
Robert F. Heinemann
President and Chief Executive Officer
November 3, 2005

Exhibit 32.2

Certification of Chief Financial Officer 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 September 30, 2005 as filed with the Securities and Exchange Commission on the date hereof (the “Report”).

I, Ralph J. Goehring, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Ralph J. Goehring
Ralph J. Goehring
Executive Vice President and
Chief Financial Officer
November 3, 2005