BERRY PETROLEUM CO
Form 10-Q
November 08, 2006

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 **September 30, 2006**
oTransition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from __to ___
Commission file number **1-9735**

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

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

5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309
(Address of principal executive offices, including zip code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filerx Accelerated filero Non-accelerated filero

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

As of October 23, 2006, the registrant had 42,038,426 shares of Class A Common Stock ($.01 par value) outstanding. The registrant also had 1,797,784 shares of Class B Stock ($.01 par value) outstanding on October 23, 2006 all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY
THIRD QUARTER 2006 FORM 10-Q
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BERRY PETROLEUM COMPANY
Unaudited Condensed Balance Sheets
(In Thousands, Except Share Information)

	September 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 352	$ 1,990
Short-term investments available for sale	663	661
Accounts receivable	66,963	59,672
Deferred income taxes	525	4,547
Fair value of derivatives	5,710	3,618
Income taxes receivable	7,638	-
Prepaid expenses and other	9,806	4,398
Total current assets	91,657	74,886
Oil and gas properties (successful efforts basis), buildings and equipment, net	1,033,222	552,984
Long-term deferred income taxes	-	1,600
Fair value of derivatives	2,782	-
Other assets	12,615	5,581
	$ 1,140,276	$ 635,051
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 73,540	$ 57,783
Property acquisition payable	102,000	-
Revenue and royalties payable	39,505	34,920
Accrued liabilities	17,895	8,805
Line of credit	20,500	11,500
Income taxes payable	-	1,237
Fair value of derivatives	12,802	15,398
Deferred income taxes	366	-
Total current liabilities	266,608	129,643
Long-term liabilities:		
Deferred income taxes	91,915	55,804
Long-term debt	309,000	75,000
Abandonment obligation	25,897	10,675
Unearned revenue	1,741	866
Fair value of derivatives	41,837	28,853
	470,390	171,198
Shareholders' equity:		
Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, $.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 42,104,176 shares issued and outstanding (21,157,155 on a pre-split basis in 2005)	421	211
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $1,798) (898,892 on a pre-split basis in 2005)	18	9
Capital in excess of par value	49,441	56,064

Accumulated other comprehensive loss	(27,847)	(24,380)
Retained earnings	381,245	302,306
Total shareholders' equity	403,278	334,210
	$ 1,140,276	$ 635,051

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Three Month Periods Ended September 30, 2006 and 2005
(In Thousands, Except Per Share Data)

	Three months ended September 30, 2006	2005 (1)
REVENUES		
Sales of oil and gas	$ 116,168	$ 96,439
Sales of electricity	12,592	12,933
Interest and other income, net	603	612
	129,363	109,984
EXPENSES		
Operating costs - oil and gas production	30,950	24,270
Operating costs - electricity generation	11,198	12,316
Production taxes	5,286	3,874
Exploration costs	344	749
Depreciation, depletion & amortization - oil and gas production	17,974	8,602
Depreciation, depletion & amortization - electricity generation	825	1,042
General and administrative	9,419	5,965
Interest	2,707	1,598
Dry hole, abandonment and impairment	183	2,803
	78,886	61,219
Income before income taxes	50,477	48,765
Provision for income taxes	19,103	14,546
Net income	$ 31,374	$ 34,219
Basic net income per share	$ .71	$ .78
Diluted net income per share	$ .70	$ .76
Dividends per share	$ .095	$ .115
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	43,907	44,136
Effect of dilutive securities:		
Equity based compensation	654	804
Director deferred compensation	104	118
Weighted average number of shares of capital stock used to calculate diluted net income per share	44,665	45,058

Unaudited Condensed Statements of Comprehensive Income
Three Month Periods Ended September 30, 2006 and 2005
(In Thousands)

Net income	$	31,374	$	34,219
Unrealized gains (losses) on derivatives, net of income taxes of $28,188 and ($11,090), respectively		42,282		(16,635)
Reclassification of realized losses included in net income net of income taxes of ($1,178) and ($2,568), respectively		(1,767)		(3,852)
Comprehensive income	$	71,889	$	13,732

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

(1) The 2005 per share and share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006. See Note 2.

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Nine Month Periods Ended September 30, 2006 and 2005
(In Thousands, Except Per Share Data)

		Nine months ended September 30,		
		2006		2005 (1)
REVENUES				
Sales of oil and gas	$	328,742	$	252,635
Sales of electricity		39,476		36,903
Interest and other income, net		1,898		1,130
		370,116		290,668
EXPENSES				
Operating costs - oil and gas production		83,763		69,356
Operating costs - electricity generation		36,155		36,596
Production taxes		11,891		8,569
Exploration costs		4,105		1,535
Depreciation, depletion & amortization - oil and gas production		47,333		26,417
Depreciation, depletion & amortization - electricity generation		2,526		2,826
General and administrative		25,610		15,988
Interest		6,745		4,502
Commodity derivatives		(736)		-
Dry hole, abandonment and impairment		6,965		5,425
		224,357		171,214
Income before income taxes		145,759		119,454
Provision for income taxes		56,930		37,470
Net income	$	88,829	$	81,984
Basic net income per share	$	2.02	$	1.86
Diluted net income per share	$	1.98	$	1.82
Dividends per share	$	.225	$	.235
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)		43,982		44,078
Effect of dilutive securities:				
Equity based compensation		792		786
Director deferred compensation		101		114
Weighted average number of shares of capital stock used to calculate diluted net income per share		44,875		44,978

Unaudited Condensed Statements of Comprehensive Income

Nine Month Periods Ended September 30, 2006 and 2005
(In Thousands)

Net income	$	88,829	$	81,984
Unrealized gains (losses) on derivatives, net of income taxes of $1,223 and ($26,407), respectively		1,834		(39,611)
Reclassification of realized losses included in net income net of income taxes of ($3,534) and ($811), respectively		(5,301)		(1,216)
Comprehensive income	$	85,362	$	41,157

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

(1) The 2005 per share and share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006. See Note 2.

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Nine Month Periods Ended September 30, 2006 and 2005
(In Thousands)

	Nine months ended September 30, 2006	2005
Cash flows from operating activities:		
Net income	$ 88,829	$ 81,984
Depreciation, depletion and amortization	49,858	29,243
Dry hole, abandonment and impairment	7,864	2,298
Commodity derivatives	(264)	-
Stock-based compensation expense	3,563	404
Deferred income taxes, net	44,410	16,939
Other, net	281	106
(Increase) in current assets other than cash, cash equivalents and short-term investments	(17,996)	(28,310)
Increase in current liabilities other than book overdraft, line of credit, property acquisition payable and fair value of derivatives	8,600	19,623
Net cash provided by operating activities	185,145	122,287
Cash flows from investing activities:		
Development and exploration of oil and gas properties	(185,773)	(83,848)
Property acquisitions	(215,726)	(105,828)
Additions to vehicles, drilling rigs and other fixed assets	(18,302)	(7,215)
Net cash used in investing activities	(419,801)	(196,891)
Cash flows from financing activities:		
Proceeds from issuance of line of credit	241,750	-
Payment of line of credit	(232,750)	-
Proceeds from issuance of long-term debt	324,700	116,000
Payment of long-term debt	(90,700)	(44,000)
Dividends paid	(9,889)	(10,362)
Debt issuance cost	(322)	(809)
Increase in book overdraft	10,196	7,718
Excess tax benefit	3,240	-
Stock option exercises	2,559	-
Repurchase of shares of common stock	(15,766)	(2,206)
Net cash provided by financing activities	233,018	66,341
Net decrease in cash and cash equivalents	(1,638)	(8,263)
Cash and cash equivalents at beginning of year	1,990	16,690
Cash and cash equivalents at end of period	$ 352	$ 8,427
Supplemental non-cash activity:		
Increase (decrease) in fair value of derivatives:		
Current (net of income taxes of ($1,491) and ($11,309), respectively)	$ 2,237	$ 16,964
Non-current (net of income taxes of $3,803 and ($15,909), respectively)	(5,704)	23,863
	$ (3,467)	$ 40,827

Net (decrease) increase to accumulated other comprehensive income				
Supplemental non-cash financing activity:				
Property acquired under deferred payment schedule	$	102,000	$	-

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

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BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

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, 2006 and December 31, 2005 and results of operations for the three and nine month periods ended September 30, 2006 and 2005 and cash flows for the nine month periods ended September 30, 2006 and 2005 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, 2005 financial statements. The December 31, 2005 Form 10-K, March 31, 2006 Form 10-Q and June 30, 2006 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. In the second quarter 2006, the Company dissolved its subsidiary, Piceance Operating Company 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, 2006 and September 30, 2005 is $12.1 million and $7.7 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

2. Stock Split

On March 1, 2006, the Company's Board of Directors approved a two-for-one stock split to shareholders of record on May 17, 2006, subject to obtaining shareholder approval of an increase in the Company's authorized shares. On May 17, 2006 the Company's shareholders approved the authorized share increase and on June 2, 2006 each shareholder received one additional share for each share in the shareholder's possession on May 17, 2006. This did not change the proportionate interest a shareholder maintained in the Company on that date. All historical shares, equity awards and per share amounts have been restated for the two-for-one stock split.

3. Recent Accounting Developments

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* was issued by the Financial Accounting Standards Board (FASB). This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for the Company's fiscal year beginning after November 15, 2007, and the Company is currently assessing the potential impact of this Statement on its financial statements.

In September 2006, Staff Accounting Bulletin ("SAB") No. 108*, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. Registrants must quantify the impact on current period financial statements of correcting all misstatements, including both those occurring in the current period and the effect of reversing those that have accumulated from prior periods. This SAB will be applied beginning with the first fiscal year ending after November 15, 2006. The adoption of SAB No. 108 should have no effect to the financial position and result of operations of the Company.

In June 2006, the FASB issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. This Interpretation is effective for fiscal years beginning after December 15, 2006. The Company is currently assessing the potential impact of this Interpretation on its financial statements.

In February 2006, SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140* was issued. This Statement resolves issues addressed in Statement 133 Implementation Issue No. D1, *Application of Statement 133 to Beneficial Interests in Securitized Financial Assets*. SFAS No. 155 will become effective for the Company's fiscal year beginning after September 15, 2006 and while the Company anticipates no impact on its financial statements based on its existing derivatives, the Company may experience a financial impact depending on the nature and extent of any new derivative instruments entered into after the effective date of SFAS No. 155.

4. Share-Based Compensation

In December 2004, SFAS No. 123(R), *Share-Based Payment*, was issued which establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires an issuer to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. In April 2005, the SEC issued a rule that SFAS No. 123(R) would be effective for annual reporting periods beginning on or after June 15, 2005. As a result, the Company adopted this statement beginning January 1, 2006. The Company previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*. Accordingly, the adoption of SFAS No. 123(R) using the modified prospective method, did not have a material impact on the Company's condensed financial statements for the three or nine months ended September 30, 2006.

Equity Compensation Plans

The 2005 Equity Incentive Plan (the 2005 Plan), approved by the shareholders in May 2005, provides for granting of equity compensation up to an aggregate of 2,900,000 shares of Common Stock. All equity grants are at market value on the date of grant and at the discretion of the Compensation Committee or the Board of Directors. The term of each employee grant did not exceed ten years from the grant date and vesting has generally been at 25% per year for 4 years or 100% after 3 years. The 2005 Plan also allows for grants to non-employee Directors. During 2005, each of the non-employee Directors received 10,000 options at the market value on the date of grant. The options granted to the non-employee Directors vest immediately. The Company generally uses a broker for issuing new shares upon option exercise.

Stock Options

Effective January 1, 2004, the Company voluntarily adopted the fair value method of accounting for its stock option plans as prescribed by SFAS No. 123, *Accounting for Stock-Based Compensation*, which was the predecessor to SFAS No. 123(R). The modified prospective method was selected as described in SFAS No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. Under this method, the Company recognized stock option compensation expense as if it had applied the fair value method to account for unvested stock options from its original effective date.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option pricing model that uses the assumptions noted in the following table. Expected volatilities are based on the historical volatility of the Company's stock. The Company uses historical data to estimate option exercises and employee terminations within the valuation model; separate groups of employees that have similar historical exercise behavior are considered separately for valuation purposes. The expected term of options granted is based on historical exercise behavior and represents the period of time that options granted are expected to be outstanding; the range given below results from certain groups of employees exhibiting different exercise behavior. The risk free rate for periods within the contractual life of the option is based on U.S. Treasury rates in effect at the time of grant.

	September 30, 2006
Expected volatility	32% - 33%
Weighted-average volatility	32%
Expected dividends	.9%
Expected term (in years)	5.3

Risk-free rate	4.7%

The following is a summary of stock option activity for the nine months ended September 30, 2006:

	Options		Weighted Average Exercise Price	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	3,110,826	$	16.76	
Granted	106,000		34.33	
Exercised	(455,890)		10.57	
Canceled/expired	(307,750)		18.64	
Balance outstanding, September 30	2,453,186		18.43	7.6 years
Balance exercisable at September 30	1,082,935	$	13.51	6.3 years

4. Share-Based Compensation (Continued)

Restricted Stock Units
Under the 2005 Equity, the Company began a long-term incentive program whereby restricted stock units (RSUs) are available for grant to certain employees. Granted RSUs generally vest at either 25% per year over 4 years or 100% after 3 years. At September 30, 2006, all RSUs are unvested and none are exercisable. Unearned compensation under the restricted stock award plan is amortized over the vesting period. The Company pays cash compensation on the RSUs in an equivalent amount of actual dividends paid on a per share basis of the Company's outstanding common stock.

The following is a summary of RSU activity for the nine months ended September 30, 2006 as follows:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	141,900	$ 30.65	
Granted	219,580	31.52	
Converted	-	-	
Canceled/expired	(20,800)	30.65	
Balance outstanding, September 30	340,680	$ 31.22	3.2 years

Other share-based compensation data

	Stock Options Nine months ended		RSUs Nine months ended	
	September 30, 2006	September 30, 2005	September 30, 2006	September 30, 2005
Weighted-average grant date fair value	$ 11.96	$ 6.12	$ 31.52	$ -
Total intrinsic value of options exercised (in millions)	10.3	11.9	-	-
Total intrinsic value of options/RSUs outstanding (in millions)	54.4	51.2	9.6	-
Total intrinsic value of options exercisable (in millions)	15.9	21.8	-	-
Total compensation cost recognized into income (in millions)	2.0	1.7	1.3	-

The total compensation cost related to nonvested awards not yet recognized on September 30, 2006 is $14.9 million and the weighted average period over which this cost is expected to be recognized is 3 years. The tax benefit realized from stock options exercised during the three and nine months ended September 30, 2006 is $.4 million and $3.7 million, respectively.

5. Derivatives

The Company entered into derivative contracts (natural gas swaps and collar contracts) on March 1, 2006 that did not qualify for hedge accounting under SFAS 133 because the price index for the location in the derivative instrument did not correlate closely with the item being hedged. These contracts were recorded in the first quarter of 2006 at their fair value on the balance sheet and the Company recognized an unrealized net loss of approximately $4.8 million on the income statement under the caption "Commodity derivatives." The Company entered into natural gas basis swaps on the same volumes and maturity dates as the previous hedges in May, 2006 which allowed for these derivatives to be designated as cash flow hedges going forward, causing an unrealized net gain of $5.6 million was recognized in the second quarter of 2006. The difference of $.8 million was recorded in other comprehensive income at the date the hedges were designated.

Additionally, on June 8, 2006 and July 10, 2006 the Company entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of the Company’s outstanding borrowings under its credit facility for five years. These interest rate swaps have been designated as cash flow hedges.

The related cash flow impact of all of the Company’s derivative activities are reflected as cash flows from operating activities.

5. Derivatives (Continued)

At September 30, 2006, the Company's net fair value of derivatives liability was $46.1 million as compared to $112.7 million at June 30, 2006 and $87.3 million at March 31, 2006. Based on NYMEX strip pricing as of September 30, 2006, the Company expects to make hedge payments under the existing derivatives of $3.5 million during the next twelve months. Accumulated other comprehensive loss consisted of $27.8 million, net of tax, of unrealized losses from the Company's crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at September 30, 2006. Deferred net losses recorded in Accumulated other comprehensive loss at September 30, 2006 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts.

6. Revisions to the Classification of Production Taxes

Certain amounts in the condensed income statements for the three and nine months ended September 30, 2005 have been reclassified to conform to the 2006 presentation. In connection with the preparation of the 2005 financial statements, the Company reclassified production taxes out of operating costs-oil and gas into a separate line. This reclassification had no impact on net income or net cash provided by operating activities and did not effect previously reported total revenues, total operating expenses, 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, 2005 as follows (in thousands):

	Three months ended September 30, 2005	Nine months ended September 30, 2005
Operating costs - oil and gas		
As previously reported	$ 28,144	$ 77,925
As revised	24,270	69,356
Difference	$ (3,874)	$ (8,569)
Production taxes		
As previously reported	$ -	$ -
As revised	3,874	8,569
Difference	$ 3,874	$ 8,569

7. Dry Hole, Abandonment and Impairment

The amount reflected on the Company's income statement under the dry hole, abandonment and impairment line item consists primarily of $.2 million for two wells that were drilled on the Company's Tri-State prospect that were determined non-commercial in the third quarter of 2006. For the nine months ended September 30, 2006 the Company incurred $7 million in dry hole, abandonment and impairment which primarily relates to two Coyote Flats, Utah wells for $5.2 million and the Company's 25% share in an exploration well located in the Lake Canyon project area of the Uinta basin drilled for approximately $1.6 million net to Berry's interest.

8. Income Taxes

The Company's effective tax rate was 38% and 39% for the third quarter and the first nine months of 2006 compared to 30% and 31% for the third quarter and first nine months of 2005. The effective tax rates were lower in 2005 due to the Company's investment in projects that qualified for enhanced oil recovery (EOR) tax credits. The federal and state EOR tax credits are fully phased out in 2006 due to the 2005 average U.S. wellhead crude oil price exceeding the allowable EOR tax credit ceiling price of $44.48 per barrel. The Company's combined federal and state statutory tax rate is 40%.

9. Credit Facility

In April 2006, the Company completed a new unsecured five-year bank credit agreement (the Agreement) with a banking syndicate and extended the term by one year to July 2011. The Agreement is a revolving credit facility for up to $750 million and replaces the previous $500 million facility. The current borrowing base was established at $500 million, as compared to the previous $350 million. This transaction was accounted for in accordance with Emerging Issues Task Force, (EITF) 98-14, Debtor's Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements.

9. Credit Facility (Continued)

The total outstanding debt under the credit facility's borrowing base and line of credit was $330 million at September 30, 2006, leaving $170 million in borrowing capacity available. Interest on amounts borrowed is charged at LIBOR plus a margin of 1.00% to 1.75% 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 .375% on the unused portion of the credit facility.

The weighted average interest rate on outstanding borrowings at September 30, 2006 was 6.5%. The Agreement contains restrictive covenants which, among other things, require the Company to maintain a certain debt to EBITDA ratio and a minimum current ratio, as defined. The Company was in compliance with all covenants as of September 30, 2006.

10. Leases Receivable

The Company entered into two separate three year lease agreements on two company owned drilling rigs. Each agreement has a three year purchase option in favor of the lessee. The agreements were signed in the third and second quarters of 2005 and 2006, respectively. The total net investment in these rigs is approximately $8.9 million at September 30, 2006. Both agreements are accounted for as direct financing leases as defined by SFAS No. 13, *Accounting for Leases*. Net investment in both leases are included in the balance sheet as other assets and as of September 30, 2006 are as follows (in thousands):

Net minimum lease payments receivable	$ 11,830
Unearned income	(2,963)
Net investment in direct financing lease	$ 8,867

As of September 30, 2006, estimated future minimum lease payments, including the purchase option, to be received are as follows (in thousands):

2006	$257
2007	1,276
2008	4,545
2009	5,752
Total	$11,830

11. Contingencies

The Company has accrued environmental liabilities for all sites, including sites in which governmental agencies have designated the Company as a potentially responsible party, where it is probable that a loss will be incurred and the minimum cost or amount of loss can be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be higher than the liability currently accrued. Amounts currently accrued are not significant to the financial position of the Company and Management believes, based upon current site assessments, that the ultimate resolution of these matters will not require substantial additional accruals. The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of Management, the resolution of these matters will not have a material effect on the Company's financial position, results of operations or liquidity.

12. Joint Venture

On June 7, 2006 the Company entered into an agreement with a party to jointly develop the North Parachute Ranch property in the Grand Valley field of the Piceance basin of western Colorado. The Company estimates it will pay up to $153 million to fund the drilling of 90 natural gas wells on the joint venture partner’s acreage. The maximum amount of cost charged to the Company will not exceed $1.7 million per well. In exchange for the Company’s payments of up to $153 million, the Company will earn a 5% working interest on each of the 90 well bores and a net working interest of 95% (79% net revenue interest) in 4,300 gross acres located elsewhere on the property.

On July 7, 2006, the Company paid $51 million, which was the first installment of the total $153 million and thereby earned the assignment of the 4,300 gross acres. On November 1, 2006, the Company paid the second installment of approximately $50 million. The Company plans to pay the third installment on May 1, 2007. Prior to 2010 the Company is required to drill 120 wells, bearing 95% of the cost, on its 4,300 gross acres and if not met, then the Company is required to pay $.2 million for each well less than 120 drilled. Additionally, if the Company has not drilled at least one well by mid-2011 in each 160 acre tract within the 4,300 gross acres, then that specific undrilled 160 acre tract shall be reassigned to the joint venture partner. At the date of the agreement there were no operating activities from these gas assets.

13. Acquisition

On February 28, 2006, the Company closed on an agreement with a private seller to acquire a 50% working interest in natural gas assets in the Piceance basin of western Colorado for approximately $159 million. The acquisition was funded under the Company's existing credit facility. The Company purchased 100% of Piceance Operating Company LLC (which owned a 50% working interest in the acquired assets). The total purchase price was allocated as follows: $30 million to proved reserves and $129 million to unproved properties. Allocation was made based on fair value. The operating activities of these oil and gas assets are insignificant compared to Berry's historical operations and therefore are omitted from disclosure. Piceance Operating Company LLC was dissolved subsequent to the acquisition.

14. Subsequent Event

On October 24, 2006, the Company issued $200 million of 8.25% senior subordinated notes due 2016 in a public offering. The deferred costs of approximately $5 million associated with the issuance of debt will be amortized over the ten year life of the bonds. The net proceeds from the offering were used to 1) repay approximately $145 million of current borrowings under the bank credit facility, which were $170 million as of October 24, 2006 after the application of this payment and 2) approximately $50 million was used to finance the November 1, 2006 installment under the joint venture agreement to develop properties in the Piceance basin.

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

General. The following discussion provides information on the results of operations for each of the three and nine month periods ended September 30, 2006 and 2005 and our financial condition, liquidity and capital resources as of September 30, 2006. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

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

Corporate Strategy. Our objective is to increase the value of our business through consistent growth in our production and reserves, both through the drill-bit and acquisitions. We strive to operate our properties in an efficient manner to maximize the cash flow and earnings of our assets. The strategies to accomplish these goals include:

- Developing our existing resource base
- Acquiring additional assets with significant growth potential
- Utilizing joint ventures with respected partners to enter new basins
- Accumulating significant acreage positions near our producing operations
- Investing our capital in a disciplined manner and maintaining a strong financial position

Notable Third Quarter Items.

- Achieved record production which averaged 26,423 BOE/D, up 12% from the third quarter of 2005 and up 7% from the second quarter of 2006
- Achieved production of approximately 5,800 Mcf/D in the Piceance basin
- Drilled four appraisal wells on our Lake Canyon acreage which are testing at commercial rates
- Increased our 2006 capital budget to $275 million to accelerate growth
- Increased our regular quarterly dividend by 15% to $.075 per share ($.30 annually) and paid a special dividend of $.02 per share
- Executed new crude oil sales contracts for Brundage Canyon oil production
- Announced our 2006 year-end reserve target of 146 million BOE
- Achieved over $1 billion in total assets as reflected in the balance sheet of the Company

Notable Items and Expectations for the Remainder of 2006.

- Announced full scale development of our California diatomite asset with a 100 well drilling program scheduled for 2007
- Begin drilling in the Ashley Forest located in the southern portion of our Brundage Canyon property
- Issued $200 million of ten year 8.25% senior subordinated notes on October 24, 2006
- Expect to determine a capital budget for 2007 in the $250 million to $275 million range

Overview of the Third Quarter. Our third quarter was our strongest quarter of the year when viewed excluding the impact of commodity derivatives in the prior quarters. We had a significant increase in average daily production of approximately 7% over the second quarter, which is a result of our drilling program and increased steam on various

California heavy oil properties. Our average realized prices were down by 5% from the second quarter reflecting a weakening commodity price environment.

View to the Fourth Quarter. Our 2006 drilling program continues to drive our production growth into the fourth quarter. We are expecting our production in the fourth quarter to increase to average over 28,000 BOE/D. We expect minimal impacts from our hedging in the fourth quarter, but do expect lower realized prices from our Uinta basin crude oil sales as the differential continues to widen. Operationally, we are focused on executing our drilling program on our assets in the Piceance basin and our diatomite resource in California and preparing for a sizable capital program in 2007.

Joint Venture. See Note 12 to the unaudited condensed financial statements.

Results of Operations. The following companywide results are in thousands (except per share data) for the three months ended:

	September 30, 2006	September 30, 2005	Change	June 30, 2006	Change
Sales of oil	$ 97,918	$ 81,791	20%	$ 94,965	3%
Sales of gas	18,250	14,648	25%	15,676	16%
Total sales of oil and gas	$116,168	$ 96,439	20%	$ 110,641	5%
Sales of electricity	12,592	12,933	(3%)	11,715	7%
Interest and other income, net	603	612	(1%)	803	(25%)
Total revenues and other income	$129,363	$ 109,984	18%	$ 123,159	5%
Net income	$ 31,374	$ 34,219	(8%)	$ 34,203	(8%)
Net income per share (diluted)	$ .70	$ .76	(8%)	$ .76	(8%)

Our 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 2006 compared to 2005 are due to a tighter supply and demand balance and the nervousness of the market about possible supply disruptions. Both oil and gas prices weakened during the third quarter of 2006 as compared to the second quarter of 2006.

Our production for the quarter ended September 30, 2006 was 26,423 BOE/D, which was up 12% from the third quarter of 2005, and an increase of 7% from the second quarter of 2006. Production averaged almost 16,200 BOE/D and 10,200 BOE/D from California and the Rockies, respectively. Our production increased by almost 1,700 BOE/D in the third quarter over the second quarter of 2006 due primarily to additional drilling and good response from our new steamfloods. Our production for the nine months ended September 30, 2006 was 24,896 BOE/D, which was up 9% from the same period last year. We are forecasting average production of between 25,500 BOE/D and 25,800 BOE/D for 2006, with well timing and completions being the largest varying factors.

In the third quarter of 2006, we incurred total combined charges of $.5 million for two dry holes on our Tri-State (DJ basin) acreage and in exploration costs which consists of our geological and geophysical costs associated with our Tri-State acreage. We project our total exploration expense for 2006 to be approximately $5 million.

In the first quarter ended March 31, 2006, we took a charge for the change in fair market value of our natural gas derivatives put in place to protect our Piceance basin acquisition future cash flows. These gas derivatives did not qualify for hedge accounting under SFAS 133 because the price index in the derivative instrument did not correlate closely with the item being hedged. The pre-tax charge in the first quarter was $4.8 million which represented the change in fair market value over the life of the contract, which resulted from an increase in natural gas prices from the date of the derivative to March 31, 2006. On May 31, 2006, the Company entered into basis swaps with natural gas volumes to match the volumes on the Company's NYMEX Henry Hub collars that were placed on March 1, 2006 and designated these swaps and collars as cash flow hedges, causing an unrealized net gain of $5.6 million to be recognized in the second quarter of 2006. The difference of $.8 million was recorded in other comprehensive income at the date the hedges were designated. Subsequent to May 31, 2006 changes in the marked-to-market fair values are reflected in Other Comprehensive Income.

Operating data. The following table is for the three months ended:

	September 30, 2006	%	September 30, 2005	%	June 30, 2006	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	16,076	61	16,701	71	15,532	63
Light Oil Production (Bbl/D)	4,118	16	3,308	14	4,061	16
Total Oil Production (Bbl/D)	20,194	76	20,009	85	19,593	79
Natural Gas Production (Mcf/D)	37,374	24	21,829	15	31,047	21
Total (BOE/D)	26,423	100	23,647	100	24,768	100
Per BOE:						
Average sales price before hedging	$ 50.33		$ 51.34		$ 52.46	
Average sales price after hedging	47.28		44.25		49.75	
Oil, per Bbl:						
Average WTI price	$ 70.54		$ 63.31		$ 70.72	
Price sensitive royalties	(5.21)		(5.68)		(5.66)	
Quality differential	(8.76)		(4.94)		(8.49)	
Crude oil hedges	(3.99)		(8.35)		(3.38)	
Average oil sales price after hedging	$ 52.58		$ 44.34		$ 53.19	
Gas, per MMBtu:						
Average Henry Hub price	$ 6.18		$ 6.97		$ 6.65	
Natural gas hedges	(.02)		.02		-	
Location and quality differentials	(1.32)		(.85)		(1.06)	
Average gas sales price after hedging	$ 4.84		$ 6.14		$ 5.59	

The following table is for the nine months ended:

	September 30, 2006	%	September 30, 2005	%
Oil and Gas				
Heavy Oil Production (Bbl/D)	15,681	63	16,086	71
Light Oil Production (Bbl/D)	3,823	15	3,301	14
Total Oil Production (Bbl/D)	19,504	78	19,387	85
Natural Gas Production (Mcf/D)	32,348	22	20,438	15
Total (BOE/D)	24,896	100	22,793	100
Per BOE:				
Average sales price before hedging	$ 50.81		$ 45.38	
Average sales price after hedging	48.33		40.48	
Oil, per Bbl:				
Average WTI price	$ 68.26		$ 55.61	
Price sensitive royalties	(5.41)		(4.22)	
Quality differential	(7.87)		(5.18)	
Crude oil hedges	(3.17)		(5.78)	
Average oil sales price after hedging	$ 51.81		$ 40.43	
Gas, per MMBtu:				
Average Henry Hub price	$ 6.91		$ 6.62	
Natural gas hedges	-		(.02)	
Location and quality differentials	(1.30)		(.78)	
Average gas sales price after hedging	$ 5.61		$ 5.82	

Oil Contracts. On November 21, 2005, we entered into a new crude oil sales contract for our California production for deliveries beginning February 1, 2006 and ending January 31, 2010. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of 1) the WTI NYMEX crude oil price less a fixed differential approximating $8.15, or 2) heavy oil field postings plus a premium of approximately $1.35.

Our weighted average realized sales price for our Utah crude oil as of October 1, 2006 under our contracts is approximately $14.50 per barrel below WTI, with certain volumes tied to field posting. In some cases, our realized price is further reduced by transportation charges. From October 1, 2003 through April 30, 2006, we sold our Utah crude oil at approximately $2 per barrel below WTI; and from May 1, 2006 through September 30, 2006, we sold the majority of our Utah crude oil at approximately $9 per barrel below WTI. Due to this lower pricing and based on sales of 4,600 Bbl/D gross, we estimate our revenues will be lower by approximately $4 million in the fourth quarter of 2006, as compared to the third quarter of 2006. If this pricing continues throughout 2007 and on the same volumes, we estimate our 2007 revenues will be lower by approximately $15 million versus our expected 2006 revenues. Field postings are currently at approximately $12 to $13 below WTI. We are working on a longer term sales contract for our crude oil, which has a high paraffinic content, and may adjust our future capital expenditures in the Uinta basin due to the actual or expected change in our realized price.

Hedging. See Note 5 to the unaudited condensed financial statements and Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Electricity. We consume natural gas as fuel to operate our 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. Revenue and operating costs in the three months ended September 30, 2006 were down from the three months ended September 30, 2005 due to 6% lower electricity prices and 21% lower natural gas prices, respectively. Conversely, revenue and operating costs in the three months ended September 30, 2006 were up from the three months ended June 30, 2006 due to 17% higher electricity prices and 3% higher natural gas prices, respectively. The following table is for the three months ended:

	September 30, 2006	September 30, 2005	June 30, 2006
Electricity			
Revenues (in millions)	$ 12.6	$ 12.9	$ 11.7
Operating costs (in millions)	$ 11.2	$ 12.3	$ 10.6
Electric power produced - MWh/D	2,100	2,025	2,023
Electric power sold - MWh/D	1,895	1,830	1,827
Average sales price/MWh	$ 79.42	$ 84.89	$ 67.88
Fuel gas cost/MMBtu (excluding transportation)	$ 5.69	$ 7.16	$ 5.55

Oil and Gas Operating, Production Taxes, G&A and Interest Expenses. The following table presents information about our operating expenses for each of the three month periods ended:

	Amount per BOE			Amount (in thousands)		
	September 30, 2006	September 30, 2005	June 30, 2006	September 30, 2006	September 30, 2005	June 30, 2006
Operating costs - oil and gas production	$ 12.73	$ 11.16	$ 12.01	$ 30,950	$ 24,270	$ 27,074
Production taxes	2.17	1.78	1.50	5,286	3,874	3,373
DD&A - oil and gas production	7.39	3.95	7.22	17,974	8,602	16,263
G&A	3.87	2.74	3.49	9,419	5,965	7,877
Interest expense	1.11	.73	1.09	2,707	1,598	2,460
Total	$ 27.27	$ 20.36	$ 25.31	$ 66,336	$ 44,309	$ 57,047

Our total operating costs, production taxes, G&A and interest expenses for the three months ended September 30, 2006, stated on a unit-of-production basis, increased 34% over the three months ended September 30, 2005 and increased 8% over the three months ended June 30, 2006. The changes were primarily related to the following items:

- Operating costs: Operating costs per BOE in the third quarter of 2006 were 14% higher than the third quarter of 2005 due to the net effect of a higher volume of steam used offset by lower costs to produce steam. During the third quarter of 2006 we installed additional steam generators in California related to various thermally enhanced oil projects. As a result of the increased steam injection, our crude oil production on these properties has continued to increase. Similarly, operating costs per BOE were 6% higher in the third quarter of 2006 as compared to the second quarter of 2006, primarily due to the 11% increase in average volume of steam injected in that time period. The cost of our steaming operations on our heavy oil properties in California vary depending on the cost of natural gas used as fuel and the volume of steam injected. The following table presents steam information:

	September 30, 2006	September 30, 2005	Change	June 30, 2006	Change
Average volume of steam injected (Bbl/D)	86,556	68,299	27%	78,322	11%
Fuel gas cost/MMBtu	\$5.69	\$7.16	(21%)	\$5.55	3%

As we remain in a strong commodity price environment, we anticipate that cost pressures within our industry may continue due to greater field activity and rising service costs in general. Natural gas prices impact our cost structure in California by approximately \$1.60 per California BOE for each \$1.00 change in natural gas price.

- Production taxes: Our production taxes have increased over the last year as the value of our oil and natural gas has increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the cost of the field sales price of the commodity and in California, our production is burdened with ad valorem taxes on our total proved reserves. In the third quarter of 2006, our production taxes were higher by 22% over the third quarter of 2005 and 45% higher than the second quarter of 2006. This is primarily due to significantly increased California and Colorado production taxes from higher assessed values on our properties, increased production and higher investment in mineral interests. We expect production taxes to track the commodity price generally. California Proposition 87, "The Clean Energy Initiative" was not passed by California voters on November 7, 2006 and thus, no new production taxes are expected.

- Depreciation, depletion and amortization: DD&A increased per BOE in the three months ended September 30, 2006 due to several sizable acquisitions, more extensive development in higher cost fields and cost pressures in our labor and capital investments. As these costs increase, our DD&A rates per BOE will also increase.

- General and administrative: Approximately two-thirds of our G&A is compensation or compensation related costs. To remain competitive in workforce compensation and attract the talent needed to achieve our growth goals, the Company's compensation costs increased in 2006. G&A increased per BOE in the three months ended September 30, 2006 compared to the three months ended June 30, 2006 due to increased compensation costs and increased contributions in the third quarter to fund the opposition of Proposition 87 in California.

- Interest expense: Our outstanding borrowings, including our line of credit, were $330 million at September 30, 2006 and $273 million at June 30, 2006. Average borrowings in 2006 increased as a result of our Piceance basin acquisitions during 2006. A certain portion of our interest cost related to our Piceance basin acquisition and joint venture has been capitalized into the basis of the assets, and we anticipate a portion will continue to be capitalized during 2006 and 2007 until our probable reserves have been recategorized to proved reserves. As of September 30, 2006, $5.6 million had been capitalized and we expect to capitalize between $8 million and $10 million of interest cost during the full year of 2006.

Estimated 2006 and Actual Nine Months Ended September 30, 2006 Oil and Gas Operating, G&A and Interest Expenses.

	Anticipated range in 2006 per BOE	Nine months ended September 30, 2006
Operating costs-oil and gas production	$ 11.75 to 13.25	$ 12.32
Production taxes	1.65 to 1.85	1.75
DD&A	6.50 to 7.50	6.96
G&A	3.60 to 3.80	3.77
Interest expense	.90 to 1.30	.99
Total	$ 24.40 to 27.70	$ 25.79

Estimated 2007 Capital Budget, Production Volume, and Oil and Gas Operating, G&A and Interest Expenses. We are in the process of determining our 2007 capital budget. Our capital expenditures should be close to our internally generated cash flow for the year targeting approximately $250 million to $275 million. Our cash flow is primarily determined by our realized commodity sales prices, and production volume. With the implementation of this capital budget, we estimate double digit growth in our production volume in 2007 which targets a minimum of 28,000 BOE/D. Based on WTI of $60 and NYMEX Henry Hub (HH) of $7.50 MMBtu, we expect our expenses to be within the following ranges:

		Anticipated range in 2007 per BOE
Operating costs-oil and gas production	$	14.00 to 15.00
Production taxes		1.75 to 2.25
DD&A		7.50 to 8.50
G&A		3.25 to 3.75
Interest expense		1.00 to 2.00
Total	$	27.50 to 31.50

Income Taxes. See Note 8 to the unaudited condensed financial statements. Our effective tax rate will be higher in 2006 as compared to 2005 due to the phase-out of the EOR tax credit in 2006. We experienced an effective tax rate in the third quarter of 38% and 39% for the nine months ended September 30, 2006, which is in line with our projections. We expect our effective tax rate for all of 2006 will be approximately 39%.

Development, Exploitation and Exploration Activity. We drilled 155 gross (127 net) wells during the third quarter of 2006, realizing a gross success rate of 99 percent. Excluding any future acquisitions, our approved 2006 capital budget is $275 million. As of September 30, 2006, we have nine rigs drilling on our properties under long term contracts, one of which we own. We have several more rigs scheduled to begin in late 2006/early 2007, including one other rig we own, which is being refurbished.

Piceance Basin
In the third quarter of 2006, we drilled or started six additional wells, four on the Garden Gulch property and two on the North Parachute Ranch property. A total of 16 wells were drilled in the first nine months of 2006. We have contracts for five rigs as of September 30, 2006. The Garden Gulch acreage now has 20 wells producing and we anticipate production from the North Parachute Ranch property late in the fourth quarter. Average net production in the third quarter 2006 was approximately 5,800 Mcf/D, up from 3,400 Mcf/D in the second quarter of 2006.

Uinta Basin
Brundage Canyon: In the third quarter we drilled 25 wells with 100% success rate. For the third quarter, daily net production averaged approximately 6,400 BOE/D. We are proceeding to drill our next Ashley Forest well in the fourth quarter of 2006.

Lake Canyon: In the third quarter we drilled four shallow Green River wells that are all productive. Initial gross production from these four wells averaged 140 BOE/D each which is consistent with the results of our Brundage Canyon wells. We are in the permitting process for an additional 32 wells which are intended to continue exploratory and development drilling on the eastern portion of our Lake Canyon acreage. The timing to begin the drilling of these wells is the second quarter 2007. Based on the success of their first Wasatch well, our industry partner is planning to drill two additional Wasatch wells in the fourth quarter of 2006.

Coyote Flats: We have three successful appraisal Ferron gas wells on the east side of the Scofield reservoir which have each tested flow rates exceeding 900 Mcf/D. We have renegotiated the farm out obligation terms with our industry partner to earn a 50% interest in the project without drilling the remaining Emery coalbed methane wells. Berry's earning obligation will be satisfied by installing a gathering system, compression and 13 mile gas pipeline to connect the three previously announced Ferron gas discoveries to sales pipelines. Construction is underway and first sales are anticipated by the end of 2006.

Denver-Julesburg Basin
In our Tri-State area, we drilled 69 wells in the third quarter of 2006. Our net production averaged 16.2 MMcf/D. In the third quarter, Berry installed additional compression, gas gathering pipelines and high pressure pipelines that expand the capacity and connections to new markets on the Cheyenne Plains Lateral system. In our Kansas Tri-State prospect we have drilled and completed a successful exploratory well that is an extension to our Prairie Star production in Cheyenne County, Kansas and have drilled two dry holes in the third quarter. We continue to permit new locations in Kansas and plan to drill several new locations in the fourth quarter of 2006.

San Joaquin Valley Basin
Midway-Sunset: Production, excluding diatomite, increased 300 Bbl/D to 11,700 Bbl/D in the third quarter versus the second quarter. Production increased as a result of accelerating the development of our Ethel D and Pan properties and from returning a number of horizontal wells to production after an aggressive cyclic steam program during the first half of 2006. During the first three quarters of 2006, we drilled infill producers and added steam generation capacity. We plan to drill an additional 10 to 15 infill producers on these properties during the fourth quarter of 2006.

Poso Creek: Production from our Poso Creek property continues to increase as a result of thermal redevelopment. Production has increased steadily throughout the year from approximately 500 Bbl/D to over 1,200

Bbl/D currently. Additional steam generation capacity was added during the third quarter and we plan to drill 20 infill producers during the fourth quarter of 2006.

Diatomite: On November 1, 2006, we announced our plans to commence development of our Midway-Sunset diatomite oil project in California based on the performance of a two-year pilot program. We believe the project will be a significant asset for our California operations and for Berry. The project will add material production and reserves to the Company as a part of our growth strategy. Over the next four years, we will invest an additional $210 million in capital to drill 520 shallow development wells in the fairway of the asset and add steam generation and processing facilities. We expect this development will increase production to 7,000 Bbl/D by 2010. As we develop the fairway, we will also appraise the potential of recovering additional reserves in the outer portions of our acreage in subsequent development phases.

We began our diatomite pilot with 13 wells in 2004 and have expanded the project. Current production is over 500 Bbl/D and the steam to oil ratio in the core of our pilot area has declined to six-to-one. Achieving this level of performance has been key to moving ahead with a development plan. We believe that the fairway contains 55% of the oil resource and has reservoir properties similar to the pilot. This will enable a repeatable development like those used in our other California assets. We will expand the project in 2007 and will spend about $50 million of capital for 100 wells and associated facilities targeting an average daily production of 1,000 Bbl/D for the year.

Drilling Activity. The following table sets forth certain information regarding drilling activities for the three and nine months ended September 30, 2006:

	Three months ended September 30, 2006			Nine months ended September 30, 2006		
	Gross Wells	Net Wells	Net Workovers	Gross Wells	Net Wells	Net Workovers
Midway-Sunset *(1)*	40	39.6	2.0	84	83.1	16.9
Poso Creek	4	4.0	6.0	22	22.0	8.0
Placerita	7	7.0	-	7	7.0	6.0
Brundage Canyon	25	25.0	-	82	82.0	14.0
Lake Canyon	4	2.0	-	5	2.3	1.0
Coyote Flats *(2)*	-	-	-	2	2.0	.5
Tri-State *(3)*	69	46.2	35.0	184	83.0	62.7
Piceance	6	3.0	-	16	8.0	-
Bakken *(4)*	-	-	-	4	.3	-
Totals	**155**	**126.8**	**43.0**	**406**	**289.7**	**109.1**

(1) Includes 1 gross well (1 net well) that was a dry hole in the second quarter of 2006.

(2) Includes 2 gross wells that were dry holes in first quarter 2006. Acreage ownership is earned upon fulfilling certain obligations.

(3) Includes 1 gross well (.3 net well) that was a dry hole in the first quarter 2006 and 2 gross wells (1.3 net wells) that were dry holes in the third quarter of 2006.

(4) Includes 1 gross well (.06 net well) that was a dry hole in the first quarter 2006.

Rocky Mountain and Mid-Continent Region Drilling Rigs. During 2005 and 2006, we purchased three drilling rigs. These rigs are leased to a drilling company under three year contracts and carry purchase options available to the drilling company, two of which are accounted for as lease receivables in Note 10. Owning these rigs allows us to successfully meet a portion of our drilling needs in both the Uinta and Piceance basins over the next several years. We have several more rigs we do not own contracted to begin drilling in late 2006/early 2007.

Financial Condition, Liquidity and Capital Resources. Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development and exploration drilling and the acquisition of properties. Fluctuations in commodity prices have been the primary reason for short-term changes in our cash flow from operating activities. The net long-term growth in our cash flow from operating activities is the result of growth in production as affected by period to period fluctuations in commodity prices. In the second quarter of 2006, we revised our five year unsecured credit facility to increase our maximum credit amount under the facility to $750 million and increased our current borrowing base to $500 million. As of September 30, 2006, we have total borrowings under the facility and line of credit of $330 million. On October 24, 2006, we completed the sale of $200 million of ten year 8.25% senior subordinated notes and paid down our borrowings under our facility by $141 million and our credit facility and line of credit availability as of November 1, 2006 was $311 million.

Capital Expenditures. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes. Excess cash generated from operations is expected to be applied toward acquisitions, debt reduction or other corporate purposes.

Excluding acquisitions, our approved capital budget for 2006 is $275 million. For 2006, we plan to invest approximately $190 million, or 69% of the approved capital budget, in our Rocky Mountain and Mid-Continent region assets, and $85 million, or 31%, in our California assets. Approximately half of the capital budget is focused on converting probable and possible reserves into proved reserves and on our appraisal and exploratory projects, while the other half is for the development of our proved reserves and facility costs. Capital expenditures, excluding acquisitions, are primarily funded out of internally generated cash flow.

Dividends. In 2006, we increased the dividend for the fourth consecutive year and the current quarterly dividend is $.075 per share. We also paid a special dividend of $.02 per share in September of 2006.

Working Capital and Cash Flows. Cash flow from operations is dependent upon the price of crude oil and natural gas and our ability to increase production and manage costs.

Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit arrangements. We use our long-term borrowings under our credit facility primarily to fund property acquisitions. Generally, we use excess cash to pay down borrowings under our credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital.

The table below compares financial condition, liquidity and capital resources changes for the three month periods ended (in millions, except for production and average prices):

	September 30, 2006	September 30, 2005	Change	June 30, 2006	Change
Production (BOE/D)	26,423	23,647	12%	24,768	7%
Average oil and gas sales prices, per BOE after hedging	$ 47.28	$ 44.25	7%	$ 49.75	(5%)
Net cash provided by operating activities	$ 101	$ 56	80%	$ 59	71%
Working capital, excluding line of credit	$ (154)	$ (27)	(470%)	$ (38)	(303%)
Sales of oil and gas	$ 116	$ 96	21%	$ 111	5%
Long-term debt, including line of credit	$ 330	$ 100	230%	$ 273	21%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 148	$32.7	353%	$ 65	128%
Dividends paid	$ 4.2	$ 5.1	(18%)	$ 2.9	45%

Contractual Obligations. Berry's contractual obligations as of September 30, 2006 are due in the years ended December 31, as follows (in thousands):

Contractual Obligations	Total	2006	2007	2008	2009	2010	Thereafter
Long-term debt and interest	$ 404,404	$ 5,021	$ 20,085	$ 20,085	$ 20,085	$ 20,085	$ 319,043
Abandonment obligations	25,897	640	740	942	991	991	21,593
Property acquisition payable	102,000	51,000	51,000	-	-	-	-
Operating lease obligations	10,836	340	1,420	1,370	1,178	956	5,572
Drilling and rig obligations	115,592	10,236	40,806	24,496	40,054	-	-
Firm natural gas transportation contracts	72,642	1,192	4,574	7,304	8,217	8,379	42,976
Total	$ 731,371	$ 68,429	$ 118,625	$ 54,197	$ 70,525	$ 30,411	$ 389,184

Long-term debt and interest - Long-term debt and related quarterly interest on the long-term debt borrowings can be paid before its maturity date without significant penalty.

Operating leases - We lease corporate and field offices in California , Colorado and Texas.

Drilling obligation - We intend to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the next four years, and our minimum obligation under our exploration and development agreement is $9.6 million. Also included above, our June 2006 joint venture agreement in the Piceance basin states that we must have 120 wells drilled by 2010 to avoid penalties of $24 million.

Drilling rig obligation - We are obligated in operating lease agreements for the use of multiple drilling rigs.

Firm natural gas transportation - We have one firm transportation contract which provides us additional flexibility in securing our natural gas supply and allows us to potentially benefit from lower natural gas prices in the Rocky Mountains compared to natural gas prices in California. We also have several long term gas transportation contracts which provide us with physical access to interstate pipelines to move gas from our producing areas to markets.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 5 to the unaudited condensed financial statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, from time to time we enter 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, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in the upside. In California, we benefit from lower natural gas pricing and elsewhere, we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by Management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging or other price protection is appropriate in accordance with Board established policy.

Currently, our hedges are in the form of swaps and collars. However, we may use a variety of hedge instruments in the future to hedge WTI or the index gas price. We have 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 we sell our produced gas in Colorado and Utah at the Colorado Interstate Gas (CIG) and Questar index prices, respectively.

The following table summarizes our hedge position as of September 30, 2006:

Term	Average Barrels Per Day	Floor/Ceiling Prices	Term	Average MMBtu Per Day	Average Price
Crude Oil Sales (NYMEX WTI) Collars			**Natural Gas Sales (NYMEX HH TO CIG) Basis Swaps**		
4th Quarter 2006	10,000	$47.50 / $70	4th Quarter 2006 Average	8,000	1.45
Full year 2007	10,000	$47.50 / $70	2007 Average	13,500	1.65
Full year 2008	10,000	$47.50 / $70	2008 Average	18,250	1.50
Full year 2009	10,000	$47.50 / $70			
Full year 2010	1,000	$60 / $80	**Natural Gas Sales (NYMEX HH)**		
			Collars		Floor/Ceiling Prices
			4th Quarter 2006	8,000	$8.00 / $9.72
			1st Quarter 2007	12,000	$8.00 / $16.70
			2nd Quarter 2007	13,000	$8.00 / $8.82
			3rd Quarter 2007	14,000	$8.00 / $9.10
			4th Quarter 2007	15,000	$8.00 / $11.39
			1st Quarter 2008	16,000	$8.00 / $15.65
			2nd Quarter 2008	17,000	$7.50 / $8.40
			3rd Quarter 2008	19,000	$7.50 / $8.50

	4th Quarter 2008	21,000	$8.00 / $9.50

The collar strike prices will allow us to protect a significant portion of our future cash flow if 1) oil prices decline below $47.50 per barrel while still participating in any oil price increase up to $70 per barrel on these volumes and 2) if gas prices decline below approximately $8 per MMBtu. These hedges improve our financial flexibility by locking in significant revenues and cash flow upon a substantial decline in crude oil or natural gas prices. It also allows us to develop our long-lived assets and pursue exploitation opportunities with greater confidence in the projected economic outcomes and allows us to borrow a higher amount under the credit facility.

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 our hedging activities, we utilize multiple counterparties on our hedges and monitor each counterparty's credit rating. We also attempt to minimize credit exposure to counterparties through diversification.

Based on NYMEX futures prices as of September 30, 2006, (WTI $67.24; HH $7.59), we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	September 30, 2006 NYMEX Futures	Impact of percent change in futures prices on earnings -20%	-10%	+ 10%	+ 20%
Average WTI Price	$ 67.24	$ 53.79	$ 60.52	$ 73.97	$ 80.69
Crude Oil gain/(loss) (in millions)	-	2.8	.2	(53.2)	(133.1)
Average HH Price	7.59	6.07	6.83	8.35	9.11
Natural Gas gain/(loss) (in millions)	2.6	19.1	9.8	(.5)	(2.8)
Net pre-tax future cash (payments) and receipts by year (in millions):					
2006	$ 1.8	$ 2.7	$ 2.2	$ 1.2	$ (4.5)
2007	1.8	8.9	5.1	(16.2)	(41.0)
2008	(1.1)	7.6	2.4	(22.8)	(50.0)
2009	.1	-	-	(15.9)	(40.4)
2010	-	2.7	.3	-	-
Total	$ 2.6	$ 21.9	$ 10.0	$ (53.7)	$ (135.9)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. On October 24, 2006, the Company issued $200 million of 8.25% senior subordinated notes due 2016 in a public offering. Total long-term debt outstanding under our credit facility at October 24, 2006 was $170 million. Interest on amounts borrowed is charged at LIBOR plus 1.0% to 1.75%, with the exception of the $100 million of principal for which we have hedges in place to fix the interest rate at 5.5% plus the credit facility's margin. Based on these borrowings, a 1% change in interest rates would have a $.7 million impact on interest expense on an annual basis.

Item 4. Controls and Procedures

As of September 30, 2006, we have carried out an evaluation under the supervision of, and with the participation of Management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities and Exchange Act of 1934, as amended.

Based on their evaluation as of September 30, 2006, the Chief Executive Officer and Chief Financial Officer have concluded that our 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 in the reports that we file or submit 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 our internal control over financial reporting during the most recently completed calendar quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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 “estimate,” “will,” “intend,” “continue,” “target,” “expect,” “achieve,” “strategy,” “future,” “may,” “goal(s),” or other comparable words or phrase negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on Management’s current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 16 of Berry’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” and all material changes are updated in Part II, Item 1A within this 10Q.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings
None.

Item 1A. Risk Factors
Material changes from the 2005 Form 10-K are as follows:

A widening of commodity differentials may adversely impact our revenues and per barrel economics.

Both our produced crude oil and natural gas are subject to pricing in the local markets where the production occurs. It is customary that such products are priced based on local or regional supply and demand factors. California heavy crude oil sells at a discount to WTI, the U.S. benchmark crude oil, primarily due to the additional cost to refine gasoline or light product out of a barrel of heavy crude. In addition, our weighted average realized sales price for our Utah crude oil as of October 1, 2006 under our contracts is approximately $14.50 per barrel below WTI with certain volumes tied to field posting, and, in some cases, our realized price is further reduced by transportation charges. Natural gas field prices are normally priced off of the NYMEX HH price, the benchmark for U.S. natural gas. While we attempt to contract for the best possible price in each of our producing locations, there is no assurance that past price differentials will continue into the future. Numerous factors may influence local pricing, such as refinery capacity, particularly for paraffinic crude, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be adversely impacted by a widening differential on the products we sell. Our oil and natural gas hedges are based on WTI or natural gas index prices, so we may be subject to basis risk if the differential on the products we sell widens from those benchmarks if we do not have a contract tied to those benchmarks. Additionally, insufficient pipeline capacity and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and gas producing areas.

Market conditions or operational impediments may hinder our access to crude oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and refineries owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of natural gas pipelines, gathering system capacity, processing facilities or refineries. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market.

Factors that can cause price volatility for crude oil and natural gas include:

- availability and capacity of refineries;
- availability of gathering systems with sufficient capacity to handle local production;
- seasonal fluctuations in local demand for production;
- local and national gas storage capacity;

- interstate pipeline capacity; and
- availability and cost of gas transportation facilities.

Our Utah crude oil is a paraffinic crude and can be processed efficiently by only a limited number of refineries. Increased production of crude oil in the region, the ability of refiners to process other higher sulfur crudes as a result of capital upgrades, as well as the increasing availability of Canadian crude oil, is putting downward pressure on the sales price of our crude oil.

Our weighted average realized sales price for our Utah crude oil as of October 1, 2006 under our contracts is approximately $14.50 per barrel below WTI, with certain volumes tied to field posting. In some cases, our realized price is further reduced by transportation charges. From October 1, 2003 through April 30, 2006, we sold our Utah crude oil at approximately $2 per barrel below WTI; and from May 1, 2006 through September 30, 2006, we sold the majority of our Utah crude oil at approximately $9 per barrel below WTI.

Due to this lower pricing and based on sales of 4,600 Bbl/D gross, we estimate our revenues will be lower by approximately $4 million in the fourth quarter of 2006, as compared to the third quarter of 2006. If this pricing continues throughout 2007 and on the same volumes, we estimate our 2007 revenues will be lower by approximately $15 million versus our expected 2006 revenues. Field postings are currently at approximately $12 to $13 below WTI. We are working on a longer term sales contract for our crude oil, which has a high paraffinic content, and may adjust our future capital expenditures in the Uinta basin due to our actual or expected change in our realized price.

We are subject to complex federal, state, regional, local and other laws and regulations that could give rise to substantial liabilities from environmental contamination or otherwise adversely affect our cost, manner or feasibility of doing business.

All facets of our operations are regulated extensively at the federal, state, regional and local levels. In addition, a portion of our leases in the Uinta basin in Utah are, and some of our future leases may be, regulated by Native American tribes. Environmental laws and regulations impose limitations on our discharge of pollutants into the environment, establish standards for our management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose on us obligations to investigate and remediate contamination in certain circumstances. We also must satisfy, in some cases, federal and state requirements for providing environmental assessments, environmental impact studies and/or plans of development before we commence exploration and production activities. Environmental and other requirements applicable to our operations generally have become more stringent in recent years, and compliance with those requirements more expensive. Frequently changing environmental and other governmental laws and regulations have increased our costs to plan, design, drill, install, operate and abandon oil and natural gas wells and other facilities, and may impose substantial liabilities if we fail to comply with such regulations or for any contamination resulting from our operations. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Furthermore, our business, results from operations and financial condition may be adversely affected by any failure to comply with, or future changes to, these laws and regulations.

In addition, we could also be liable for the investigation or remediation of contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage. Such liabilities may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate, and may arise even where the contamination does not result from any noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. We have incurred expenses and penalties in connection with remediation of contamination in the past, and we may do so in the future. From time to time we have experienced accidental spills, leaks and other discharges of contaminants at some of our properties, as have other similarly situated oil and gas companies, and some of the properties that we have acquired, or in which we may hold an interest but not operational control, may have past or ongoing contamination for which we may be held responsible.

Some of our operations are in environmentally sensitive areas, including coastal areas, wetlands, areas that may provide habitat for endangered or threatened species, and other protected areas, and our operations in such areas must satisfy additional regulatory requirements. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed certain drilling projects and/or access to prospective lands and have filed litigation to attempt to stop such projects, including decisions by the Bureau of Land Management regarding several leases in Utah that we have been awarded.

Our activities are also subject to the regulation by oil and natural gas-producing states and one Native American tribe of conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from federal, state, local and Native American tribal authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions that are more expensive than we have anticipated could have a negative effect on our ability to explore on or develop our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

Future environmental regulations, including potential state and federal restrictions on greenhouse gasses that may be passed in response to climate change concerns, could increase our costs to operate and produce our properties and also reduce the demand for the oil we produce. While we continue to diversify our asset base by acquiring additional natural gas assets, our business, results from operations and financial condition may be adversely affected by future restrictions.

Furthermore, we benefit from federal energy laws and regulations that relieve our cogeneration plants, all of which are Qualifying Facility (QFs), from compliance with extensive federal and state regulations that control the financial structure of electricity generating plants, as well as the prices and terms on which electricity may be sold by those plants. These federal energy regulations also require that electric utilities purchase electricity generated by our cogeneration plants at a price based on the purchasing utility's avoided cost, and that the utility sell back-up power to us on a non-discriminatory basis. The term "avoided cost" is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. These regulations have recently been amended; and a utility may now petition the Federal Energy Regulation Commission (FERC) to be relieved of its obligation to enter into any new contracts with us, if the FERC determines that a competitive electricity market is available to us in our service territory.

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

In June 2005, the Company announced that its Board of Directors authorized a share repurchase program for up to an aggregate of $50 million of the Company's outstanding Class A Common Stock. In December 2005, the Company adopted a plan under Rule 10b5-1 of the Securities Exchange Act of 1934 to facilitate the repurchase of its shares of common stock. Rule 10b5-1 allows a company to purchase its shares at times when it would not normally be in the market due to possession of nonpublic information, such as the time immediately preceding its quarterly earnings releases. This 10b5-1 plan is authorized under, and is administered consistent with, the Company's $50 million share repurchase program. All repurchases of common stock are made in compliance with regulations set forth by the SEC and are subject to market conditions, applicable legal requirements and other factors. For the three months ended September 30, 2006, the Company repurchased 92,500 shares for approximately $3 million. Since June 2005, total shares repurchased through September 30, 2006 are 500,200 for approximately $22.1 million.

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum approximate dollar value of shares that may yet be purchased under the plans or programs (in thousands)
First Quarter 2006	60,000	$ 30.04	60,000	$ 41,882
Second Quarter 2006	347,700	31.55	347,700	30,913
July 2006	75,000	32.50	75,000	28,475
August 2006	17,500	31.79	17,500	27,919
Total	500,200	$ 31.52	500,200	$ 27,919

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
3.1* Registrant's Restated Certificate of Incorporation (filed as Exhibit 3.1 on Form 8-K filed on August 8, 2006, file number 1-9735).
4.1* Registrant's 8.25% Senior Subordinated Notes (filed as Form 425B5 on October 19, 2006).
10.1* Form of Change in Control Severance Protection Agreement (filed as Exhibit 99.1 on Form 8-K filed on August 24, 2006, file number 1-9735).
10.2* Underwriting Agreement dated October 18, 2006 by and between Berry Petroleum Company and the several Underwriters listed in Schedule 1 thereto (filed as Exhibit 1.1 on Form 8-K filed on October 19, 2006, file number 1-9735).
10.3* First Supplemental Indenture dated October 24, 2006 (filed as Exhibit 4.1 on Form 8-K filed on October 26, 2006, file number 1-9735).
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.

* Incorporated by reference

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 8, 2006