BERRY PETROLEUM CO
Form 10-Q
July 25, 2008

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 June 30, 2008
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)

1999 Broadway, Suite 3700
Denver, Colorado 80202
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: (303) 999-4400

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filerx Accelerated filero Non-accelerated filero Smaller reporting companyo

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 July 14, 2008, the registrant had 42,716,259 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 July 14, 2008 all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY
SECOND QUARTER 2008 FORM 10-Q
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BERRY PETROLEUM COMPANY
Unaudited Condensed Balance Sheets
(In Thousands, Except Share Information)

	June 30, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,583	$ 316
Short-term investments	65	58
Accounts receivable	143,423	117,038
Deferred income taxes	107,965	28,547
Fair value of derivatives	-	2,109
Assets held for sale	-	1,394
Prepaid expenses and other	13,835	11,557
Total current assets	270,871	161,019
Oil and gas properties (successful efforts basis), buildings and equipment, net	1,405,560	1,275,091
Other assets	73,885	15,996
	$ 1,750,316	$ 1,452,106
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 134,872	$ 90,354
Revenue and royalties payable	30,242	47,181
Accrued liabilities	21,443	21,653
Line of credit	-	14,300
Income taxes payable	7,661	2,591
Fair value of derivatives	301,776	95,290
Total current liabilities	495,994	271,369
Long-term liabilities:		
Deferred income taxes	87,858	128,824
Long-term debt	511,000	445,000
Abandonment obligation	40,051	36,426
Unearned revenue	57	398
Other long-term liabilities	4,801	1,657
Fair value of derivatives	322,560	108,458
	966,327	720,763
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; 42,716,259 shares issued and outstanding (42,583,002 in 2007)	426	425
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899) (1,797,784 in 2007)	18	18
Capital in excess of par value	75,075	66,590
Accumulated other comprehensive loss	(386,637)	(120,704)
Retained earnings	599,113	513,645
Total shareholders' equity	287,995	459,974

	$ 1,750,316	$ 1,452,106

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

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Three Month Periods Ended June 30, 2008 and 2007
(In Thousands, Except Per Share Data)

	Three months ended June 30, 2008	2007
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 185,332	$ 113,426
Sales of electricity	16,979	13,867
Gas marketing	11,531	-
Gain on sale of assets	-	50,400
Interest and other income, net	1,564	1,536
	215,406	179,229
EXPENSES		
Operating costs - oil and gas production	55,185	35,725
Operating costs - electricity generation	15,515	11,083
Production taxes	7,481	4,139
Depreciation, depletion & amortization - oil and gas production	29,073	23,397
Depreciation, depletion & amortization - electricity generation	652	961
Gas marketing	11,071	-
General and administrative	11,160	9,651
Interest	3,951	4,976
Commodity derivatives	59	-
Dry hole, abandonment, impairment and exploration	3,464	3,519
	137,611	93,451
Income before income taxes	77,795	85,778
Provision for income taxes	28,654	33,821
Net income	$ 49,141	$ 51,957
Basic net income per share	$ 1.10	$ 1.18
Diluted net income per share	$ 1.08	$ 1.16
Dividends per share	$ .075	$ .075
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share	44,478	44,029
Effect of dilutive securities:		
Equity based compensation	1,003	751
Director deferred compensation	127	115
	45,608	44,895

Weighted average number of shares of capital stock used to calculate diluted net income per share				

Unaudited Condensed Statements of Comprehensive (Loss) Income
Three Month Periods Ended June 30, 2008 and 2007
(In Thousands)

Net income	$	49,141	$	51,957
Unrealized gains (losses) on derivatives, net of income tax benefits of ($162,792) and ($4,395), respectively		(260,225)		(6,593)
Reclassification of realized gains (losses) on derivatives included in net income, net of income taxes (benefit) of $21,898 and ($697), respectively		37,268		(1,045)
Comprehensive (loss) income	$	(173,816)	$	44,319

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Six Month Periods Ended June 30, 2008 and 2007
(In Thousands, Except Per Share Data)

	Six months ended June 30, 2008		2007	
REVENUES AND OTHER INCOME ITEMS				
Sales of oil and gas	$	349,827	$	215,200
Sales of electricity		32,906		28,463
Gas marketing		14,762		-
Gain on sale of assets		414		50,398
Interest and other income, net		2,893		2,647
		400,802		296,708
EXPENSES				
Operating costs - oil and gas production		96,814		69,335
Operating costs - electricity generation		31,914		25,254
Production taxes		13,448		7,954
Depreciation, depletion & amortization - oil and gas production		56,148		42,122
Depreciation, depletion & amortization - electricity generation		1,345		1,723
Gas marketing		14,053		-
General and administrative		22,543		19,958
Interest		7,689		9,267
Commodity derivatives		767		-
Dry hole, abandonment, impairment and exploration		7,590		4,168
		252,311		179,781
Income before income taxes		148,491		116,927
Provision for income taxes		56,319		46,115
Net income	$	92,172	$	70,812
Basic net income per share	$	2.07	$	1.61
Diluted net income per share	$	2.03	$	1.58
Dividends per share	$	.15	$	.15
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share		44,435		43,973
Effect of dilutive securities:				
Equity based compensation		924		668
Director deferred compensation		124		113
		45,483		44,754

Weighted average number of shares of capital stock used to calculate diluted net income per share		

Unaudited Condensed Statements of Comprehensive (Loss) Income
Six Month Periods Ended June 30, 2008 and 2007
(In Thousands)

Net income	$ 92,172	$ 70,812
Unrealized gains (losses) on derivatives, net of income tax benefits of ($203,141) and ($12,457), respectively	(320,748)	(18,685)
Reclassification of realized gains (losses) on derivatives included in net income, net of income taxes (benefit) of $33,596 and ($882), respectively	54,815	(1,323)
Comprehensive (loss) income	$ (173,761)	$ 50,804

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

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Six Month Periods Ended June 30, 2008 and 2007
(In Thousands)

	Six months ended June 30, 2008	2007
Cash flows from operating activities:		
Net income	$ 92,172	$ 70,812
Depreciation, depletion and amortization	57,493	43,845
Dry hole and impairment	5,332	3,547
Commodity derivatives	(257)	675
Stock-based compensation expense	4,412	3,779
Deferred income taxes	39,030	39,695
Unrealized loss on ineffective hedges	751	-
Gain on sale of oil and gas properties	(414)	(50,398)
Other, net	689	415
Change in book overdraft	13,075	(4,060)
Cash paid for abandonment	(2,127)	(625)
Increase in current assets other than cash and cash equivalents	(29,294)	(5,066)
Increase (decrease) in current liabilities other than book overdraft, line of credit and fair value of derivatives	12,952	(14,635)
Net cash provided by operating activities	193,814	87,984
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(168,382)	(148,452)
Property acquisitions	(380)	(56,106)
Additions to vehicles, drilling rigs and other fixed assets	(3,201)	(2,052)
Deposit on potential acquisition	(59,000)	-
Proceeds from sale of assets	1,809	61,258
Capitalized interest	(8,463)	(8,365)
Net cash used in investing activities	(237,617)	(153,717)
Cash flows from financing activities:		
Proceeds from issuances on line of credit	187,100	203,800
Payments on line of credit	(201,400)	(210,300)
Proceeds from issuance of long-term debt	286,300	179,300
Payments on long-term debt	(220,300)	(104,300)
Dividends paid	(6,705)	(6,678)
Proceeds from stock option exercises	2,640	2,595
Excess tax benefit and other	1,435	1,215
Net cash provided by financing activities	49,070	65,632
Net increase (decrease) in cash and cash equivalents	5,267	(101)
Cash and cash equivalents at beginning of year	316	416
Cash and cash equivalents at end of period	$ 5,583	$ 315

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

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 June 30, 2008 and December 31, 2007 and results of operations and comprehensive (loss) income and cash flows for the three month and six month periods ended June 30, 2008 and 2007 have been included. All such adjustments, except as described below, 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, 2007 financial statements. The December 31, 2007 Form 10-K/A 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.

Our cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at June 30, 2008 and December 31, 2007 is $20.8 million and $7.8 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Certain reclassifications have been made to prior period financial statements to conform them to the current year presentation. Specifically, the change in book overdraft line in the Statements of Cash Flows is classified as an operating activity to reflect the use of these funds in operations, rather than their prior year classification as a financing activity.

In March 2008, we determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. We concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, the error was corrected during the first quarter of 2008, with the effect of increasing our sales of oil and gas and accounts receivable by $10.5 million and $2.4 million, respectively, and reducing our royalties payable by $8.1 million.

In December 2007, we entered into a second long-term (ten year) firm transportation contract for our Colorado natural gas production. This contract is for 25,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. We have a total of 35,000 MMBtu/D contracted on the REX pipeline. We pay a demand charge for this capacity and our own production did not fill that capacity. To maximize the utilization of our firm transportation, we bought our partners' share of the gas produced in the Piceance basin at the market rate for that area and used our excess transportation to move this gas to the sales point. The net of our gas marketing revenue and our gas marketing expense in the Statements of Income is $.7 million for the six month period ended June 30, 2008.

In addition, Berry has signed a binding precedent agreement with El Paso Corporation for an average of 35,000 MMBtu/d of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. While it is not certain that this new line will be constructed, the expectation is that the project will proceed and be in service by 2011. As part of this agreement, we also secured firm transportation from the Piceance basin to Opal.

In the first six months of 2008, we recorded a total of $7.6 million in dry hole, abandonment, impairment and exploration expense. Charges of $2.7 million and $2.6 million were recorded during the first and second quarters of 2008, respectively, for technical difficulties that were encountered on four wells in the Piceance basin before reaching total depth. These holes were abandoned in favor of drilling to the same bottom hole location by drilling new wells. In addition, $2.3 million of exploration expense was recorded for exploration activities which were primarily 3-D seismic activity in the DJ basin.

The price sensitive royalty that burdens our Formax property in the South Midway Sunset field has changed. We previously paid a royalty equal to 75% of the amount of the heavy oil posted above a price of $16.11. This price escalates at 2% annually. Effective January 1, 2008, the royalty rate is reduced from 75% to 53% as long as we maintain a minimum steam injection level, which we expect to meet, that reduces over time. Current net production from this property is approximately 2,300 Bbl/D.

During the second quarter of 2008, Berry signed a Purchase and Sale Agreement for the acquisition of certain interests in natural gas producing properties on 4,500 net acres in Limestone and Harrison Counties of East Texas for an initial purchase price of $622 million, subject to normal closing adjustments. Berry paid $59 million to the seller upon signing the agreement as a deposit on the purchase price which is included with Other Assets in the Balance Sheet as of June 30, 2008. See the discussion of the acquisition closing in Footnote 9 of these financial statements.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

1. General (Cont'd)

Proceeds from the first quarter 2008 sale of our Prairie Star assets were $1.8 million and are reflected in the Statements of Cash Flows. The gain from that sale is $.4 million and is reflected in the Statements of Income for the six month period ended June 30, 2008.

2. Recent Accounting Developments

In December 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 160, Noncontrolling Interests in Consolidated Financial Statements. SFAS 160 was issued to establish accounting and reporting standards for the noncontrolling interest in a subsidiary (formerly called minority interests) and for the deconsolidation of a subsidiary. We do not expect the adoption of SFAS 160 to have a material effect on our financial statements and related disclosures. The effective date of this Statement is the same as that of the related Statement 141(R).

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which expands the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply the principle before that date. We may experience a financial statement impact depending on the nature and extent of any new business combinations entered into after the effective date of SFAS No. 141(R).

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Expanded disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement will require us to provide the additional disclosures described above.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This Statement is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. We do not expect the adoption of SFAS 162 to have a material effect on our financial statements or related disclosures.

3. Fair Value Measurement

In September 2006, SFAS No. 157, Fair Value Measurements was issued by the FASB. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. We adopted this Statement as of January 1, 2008.

Determination of fair value

We have established and documented a process for determining fair values. Fair value is based upon quoted market prices, where available. We have various controls in place to ensure that valuations are appropriate. These controls include: identification of the inputs to the fair value methodology through review of counterparty statements and other supporting documentation, determination of the validity of the source of the inputs, corroboration of the original source of inputs through access to multiple quotes, if available, or other information and monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

3. Fair Value Measurement (Cont'd)

Valuation hierarchy
SFAS 157 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.
- Level 1 - inputs to the valuation methodology that are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology that include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology that are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement.

Our oil swaps, natural gas swaps and interest rate swaps are valued using the counterparties' mark-to-market statements which are validated by our internally developed models and are classified within Level 2 of the valuation hierarchy. The observable inputs include underlying commodity and interest rate levels and quoted prices of these instruments on actively traded markets. Derivatives that are valued based upon models with significant unobservable market inputs (primarily volatility), and that are normally traded less actively are classified within Level 3 of the valuation hierarchy. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps.

Assets and liabilities measured at fair value on a recurring basis

June 30, 2008 (in millions)	Total carrying value on the condensed Balance Sheet	Level 2	Level 3
Commodity derivatives	$619.5	$49.9	$569.6
Interest rate swaps	4.8	4.8	-
Total liabilities at fair value	$624.3	$54.7	$569.6

Changes in Level 3 fair value measurements
The table below includes a rollforward of the Balance Sheet amounts (including the change in fair value) for financial instruments classified by us within Level 3 of the valuation hierarchy. When a determination is made to classify a financial instrument within Level 3 of the valuation hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources).

(in millions)	Three months ended June 30, 2008	Six months ended June 30, 2008
Fair value, beginning of period	$243.9	$ 194.3
	326.1	401.6

Total realized and unrealized gains and (losses) included in sales of oil and gas		
Purchases, sales and settlements, net	(.4)	(26.3)
Transfers in and/or out of Level 3	-	-
Fair value, June 30, 2008	$569.6	$569.6
Total unrealized gains and (losses) included in income related to financial assets and liabilities still on the condensed balance sheet at June 30, 2008	$ -	$-

In February of 2007, the FASB issued SFAS 159, which is effective for fiscal years beginning after November 15, 2007. SFAS 159 provides an option to elect fair value as an alternative measurement for selected financial assets and financial liabilities not previously carried at fair value. We adopted this statement at January 1, 2008, but did not elect fair value as an alternative for any financial assets or liabilities.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

4. Hedging

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At June 30, 2008, our net fair
value of derivatives liability was $624.3 million as compared to $201.6 million at December 31, 2007 which reflects increases in commodity prices in the period. Based on NYMEX strip pricing as of June 30, 2008, we expect to make hedge payments under the existing derivatives of $303.9 million during the next twelve months. At June 30, 2008, Accumulated Other Comprehensive Loss consisted of $386.6 million, net of tax, of unrealized losses from our crude oil and natural gas swaps and collars that qualified for
hedge accounting treatment at June 30, 2008. Deferred net losses recorded in Accumulated Other Comprehensive Loss at June 30, 2008 and subsequent mark-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts.
We entered into the following natural gas hedges during the three months ended March 31, 2008:
- Swaps on 15,400 MMBtu/D at $8.50 for the full year of 2009 and basis swaps on the same volumes for average prices of $1.17, $1.12, $.97, and $1.05 for each of the four quarters of 2009, respectively.

These hedges have been designated as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. These swaps were not highly effective at inception, so we subsequently entered into basis swaps and established effectiveness at that time. We did not enter into any hedges during the three months ended June 30, 2008. In 2007, we entered into natural gas swap contracts that were not highly effective. We recognized an unrealized net loss of approximately $.1 million and $.8 million on the income statement under the caption "Commodity derivatives" in the three and six months ended June 30, 2008, respectively.

5. Asset Retirement Obligations

Inherent in the fair value calculation of the asset retirement obligation (ARO) are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

Under SFAS 143, the following table summarizes the change in abandonment obligation for the six months ended June 30, 2008 (in thousands):

Beginning balance at January 1	$ 36,426
Liabilities incurred	2,102
Liabilities settled	(2,127)
Revisions in estimated liabilities	2,006
Accretion expense	1,644
Ending balance at June 30	$ 40,051

6. Income Taxes

The effective tax rate was 37% for the second quarter of 2008 compared to 39% for the first quarter of 2008 and 39% for the second quarter of 2007. The lower rate in the second quarter reflects changes in our state income apportionment which includes the projected income from our East Texas acquisition. Our rate differs from the combined federal and state statutory tax rate (net of the federal benefit), primarily due to certain business incentives.

As of June 30, 2008, we had a gross liability for uncertain tax benefits of $12.9 million of which $10.5 million, if recognized, would affect the effective tax rate. There were no significant changes to the calculation since year end 2007.

Due to the uncertainty about the periods in which examinations will be completed and limited information related to current audits, we are not able to make reasonably reliable estimates of the periods in which cash settlements will occur with taxing authorities for the noncurrent liabilities.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

7. Long-term and Short-term Debt Obligations

Short-term debt
In 2005, we completed an unsecured uncommitted money market line of credit (Line of Credit). Borrowings under the Line of Credit may be up to $30 million for a maximum of 30 days. The Line of Credit may be terminated at any time upon written notice by either us or the lender. At June 30, 2008 the outstanding balance under this Line of Credit was zero. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1%. The weighted average interest rate on outstanding borrowings on the Line of Credit at June 30, 2008 was 3.4%.

Long-term debt
In 2006, we issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Notes). The deferred costs of approximately $5 million associated with the issuance of this debt are being amortized over the ten year life of the Notes.

We have a senior unsecured bank credit facility agreement (the Agreement) with a banking syndicate through June 30, 2011. The Agreement is a revolving credit facility for up to $750 million. In 2007, we increased our borrowing base to $550 million and in the second quarter of 2008, we increased our annual borrowing base to $650 million with a funding commitment from our banking
syndicate to $600 million. The outstanding Line of Credit reduces our borrowing capacity available under the Agreement. We amended this facility in July 2008 (see footnote 9 Subsequent Events in these financial statements).

The total outstanding debt at June 30, 2008 under the credit facility and the short-term Line of Credit was $311 million and zero, respectively, leaving $339 million in borrowing capacity available. Interest on amounts borrowed under this debt 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. We are required under the Agreement to pay an annual commitment fee of .25% to .375% on the unused portion of the credit facility.

The maximum amount available is subject to an annual redetermination of the borrowing base in accordance with the lender's customary procedures and practices. Both we and the banks have bilateral rights to one additional redetermination each year.

The Agreement contains restrictive covenants which, among other things, require us to maintain a certain debt to EBITDA ratio and a minimum current ratio, as defined. The $200 million Notes are subordinated to our credit facility indebtedness. As long as the interest coverage ratio (as defined) is met, we may incur additional debt. We were in compliance with all covenants as of June 30, 2008. The weighted average interest rate on total outstanding borrowings at June 30, 2008 was 5.6%.

Additionally, in 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility for five years. These interest rate swaps have been designated as cash flow hedges.

8. Contingencies and Commitments

We have no accrued environmental liabilities for our sites, including sites in which governmental agencies have designated us as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot be reasonably estimated. However, 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 incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in substantial costs incurred. We are involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of our business. In the opinion of management, the resolution of these matters will not have a material effect on our financial position, or on the results of operations or liquidity.

In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. The refiner has increased its total purchase volume capacity to 5,000 Bbl/D as provided in our contract. The differential under the contract, which includes transportation and gravity adjustments, is linked to WTI and would range from $20 to $30 per barrel at WTI prices between $80 and $120 per barrel. Gross oil production averaged approximately 4,000 BOE/D in the quarter ended June 30, 2008.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

9. Subsequent Events

On July 15, 2008, we closed on the previously announced acquisition of certain interests in natural gas producing properties on 4,500 net acres in Limestone and Harrison Counties of East Texas. The acquisition adds approximately 32 million cubic feet equivalent per day to our production from approximately 100 producing wells. The adjusted purchase price is $653 million, including closing adjustments of $32 million based on the effective date of February 1, 2008. The acquisition was initially financed by bank borrowings under the Company's amended and restated credit agreement.

Also, on July 15, 2008, we entered into a five-year amended and restated credit agreement (the "Credit Agreement") with Wells Fargo Bank, N.A as administrative agent and a syndicate of other lenders. The secured revolving credit facility amends and restates our previous credit agreement dated as of April 28, 2006, as amended. The Credit Agreement is a $1.5 billion revolving facility with an initial borrowing base of $1 billion. Interest on amounts borrowed under this debt is charged at either LIBOR plus a margin of 1.125% to 1.875% or the prime rate plus a margin with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. Additionally, an annual commitment fee of .25% to .375% is charged on the unused portion of the credit facility. Borrowings under the Credit Agreement are secured by various of our assets and the Credit Agreement and related documents contain customary covenants similar to our previous credit facility and restrictions on the secured assets. The Credit Agreement matures on July 15, 2013. In conjunction with securing our credit facility we also secured our Line of Credit.

On July 15, 2008, we borrowed approximately $594 million under the Credit Agreement to pay the remaining consideration due for the East Texas acquisition. As of July 15, 2008, we had approximately $75 million available to be drawn under our $1 billion credit facility.

Additionally, we entered into a commitment letter with certain lenders to execute a $100 million senior unsecured revolving credit facility. The execution of definitive documentation of the unsecured credit facility is subject to completion of due diligence by the Lenders and is expected to occur no later than July 31, 2008. The unsecured credit facility is expected to mature on December 31, 2008 and will have usual and customary conditions, representations and warranties.

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 the three and six month periods ended June 30, 2008 and 2007 and our financial condition, liquidity and capital resources as of June 30, 2008. 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 global 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.

Overview. We seek to increase shareholder value 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 Second Quarter Items.

- Achieved record production averaging 29,000 BOE/D, up 7% from the second quarter of 2007 and up 3% from the first quarter of 2008
- Increased Piceance net average production to 20.8 MMcf/D in the month of June, up 24% from the first quarter of 2008
- Increased Diatomite net production to an average of 1,700 BOE/D, up 24% from the first quarter of 2008
- Production at Poso Creek averaged 3,200 Bbl/D, up 19% from the first quarter of 2008
- Achieved a production exit rate of 30,000 BOE/D
- Completed relocation of our corporate headquarters from Bakersfield, California to Denver, Colorado
- Announced that David D. Wolf would join the Company as Executive Vice President and Chief Financial Officer

Notable Items and Expectations for the Third Quarter of 2008.

- Closed on the acquisition of 4,500 acres in Limestone and Harrison Counties of East Texas on July 15, 2008, adding an estimated 32 MMcf/D to production
- Increased our 2008 capital budget by $75 million to $370 million to fund the development of our East Texas acquisition
- Entered into an amended and restated secured credit facility with a $1 billion borrowing base
- Targeting a production average of approximately 35,000 BOE/D in the third quarter and a 2008 exit rate of between 39,000 and 40,000 BOE/D

Overview of the Second Quarter of 2008. We had net income of $49 million, or $1.08 per diluted share and net cash from operations was $107 million. We drilled 120 gross wells and capital expenditures, excluding property acquisitions, totaled $95 million. We achieved average production of 29,000 BOE/D in the second quarter of 2008, up 3% from an average of 28,066 BOE/D in the first quarter of 2008.

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

	June 30, 2008 (2Q08)	June 30, 2007 (2Q07)	2Q08 to 2Q07 Change	March 31, 2008 (1Q08)	2Q08 to 1Q08 Change
Sales of oil	$ 146	$ 94	55%	$ 131	11%
Sales of gas	39	19	105%	33	19%
Total sales of oil and gas	$ 185	$ 113	64%	$ 164	13%
Sales of electricity	17	14	21%	16	6%
Gain on sale of assets	-	50	-%	-	-%
Other revenues	13	2	550%	5	160%
Total revenues and other income	$ 215	$ 179	20%	$ 185	16%
Net income	$ 49	$ 52	(6%)	$ 43	14%
Earnings per share (diluted)	$ 1.08	$ 1.16	(7%)	$ .95	14%

Our revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. Crude oil sales in the three months ended June 30, 2008 were 11% higher than the three months ended March 31, 2008 resulting from price increases of 6% and sales volume increases of 5%. Gas sales in the three months ended June 30, 2008 were 19% higher than the three months ended March 31, 2008 resulting from production increases of 3% and a price increase of 16%. Net income decreased 6% from the second quarter of 2007 to the second quarter of 2008 in part due to the $50.4 million pretax gain on the sale of assets during the second quarter of 2007.

In the first quarter of 2008, we determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. We concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, this error was corrected during the first quarter of 2008, with the effect of increasing our sales of oil and gas by $10.5 million and reducing our royalties payable.

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

		June 30, 2008	%		June 30, 2007	%		March 31, 2008	%
Heavy Oil Production (Bbl/D)		16,888	58		16,129	59		16,375	58
Light Oil Production (Bbl/D)		3,723	13		4,034	15		3,510	13
Total Oil Production (Bbl/D)		20,611	71		20,163	74		19,885	71
Natural Gas Production (Mcf/D)		50,339	29		42,193	26		49,086	29
Total (BOE/D)		29,000	100		27,195	100		28,066	100
Oil and gas, per BOE:									
Average sales price before hedging	$	91.89		$	44.72		$	71.67	
Average sales price after hedging		69.77			45.43			60.43	
Oil, per Bbl:									
Average WTI price	$	123.80		$	65.02		$	97.82	
Price sensitive royalties		(5.92)			(4.20)			(4.47)	
Quality differential and other		(11.52)			(9.24)			(10.78)	
Crude oil hedges		(29.37)			(.52)			(15.60)	
Correction to royalties payable		-			-			5.85	
Average oil sales price after hedging	$	76.99		$	51.06		$	72.82	
Natural gas price:									
Average Henry Hub price per MMBtu	$	10.93		$	7.55		$	8.05	
Conversion to Mcf		.55			.38			.40	
Natural gas hedges		(.69)			.71			(.12)	
Location, quality differentials and other		(2.15)			(3.53)			(.90)	
Average gas sales price after hedging	$	8.64		$	5.11		$	7.43	

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

		June 30, 2008	%		June 30, 2007	%
Heavy Oil Production (Bbl/D)		16,631	58		16,112	61
Light Oil Production (Bbl/D)		3,617	13		3,643	14
Total Oil Production (Bbl/D)		20,248	71		19,755	75
Natural Gas Production (Mcf/D)		49,712	29		39,463	25
Total (BOE/D)		28,534	100		26,332	100
Oil and gas, per BOE:						
Average sales price before hedging	$	84.02		$	44.25	
Average sales price after hedging		67.23			44.72	
Oil, per Bbl:						
Average WTI price	$	111.12		$	61.68	
Price sensitive royalties		(5.21)			(3.97)	
Quality differential and other		(11.15)			(9.01)	
Crude oil hedges		(22.66)			(.24)	
Correction to royalties payable		2.85			-	
Average oil sales price after hedging	$	74.95		$	48.46	
Natural gas price:						
Average Henry Hub price per MMBtu	$	9.49		$	7.16	
Conversion to Mcf		.47			.36	
Natural gas hedges		(.41)			.44	
Location, quality differentials and other		(1.50)			(2.12)	
Average gas sales price after hedging	$	8.05		$	5.84	

Gas Basis Differential. The basis differential between Henry Hub (HH) and Colorado Interstate Gas (CIG) index narrowed due to the increased take away capacity added by the start up of the Rockies Express Pipeline (REX) in January. However, the differential widened again in the second quarter. In the first quarter of 2008, the CIG basis differential per MMBtu, based upon first-of-month values, averaged $1.07 below HH and ranged from $.91 to $1.19 below HH. For the second quarter, the differential averaged $2.46 with the range going from $1.78 at the start of the quarter to $3.24 below HH at the end of the quarter. We have contracted a total of 35,000 MMBtu/D on the REX pipeline under two separate transactions to provide firm transportion for our Piceance basin gas production. After the REX startup in 2008, all of the Piceance basin gas was sold at mid-continent (ANR, NGPL or PEPL) indexes which averaged approximately $.70 above the CIG index pricing before the cost of transportation.

Gas from the Uinta basin sold for approximately $.03 below CIG pricing before deducting the cost of pipeline transport. A portion of the Uinta gas is priced on the Questar index while the remainder is based upon the CIG or NWPL index.

DJ Basin gas is priced using one of two indices. Approximately two-thirds of our volume from our DJ natural gas properties is tied to the Panhandle Eastern Pipeline (PEPL) index for pricing and the remaining volume to CIG pricing. For that portion of the production with firm transportation on either the Cheyenne Plains Pipeline or the KMIGT pipeline, pricing is based upon the PEPL index which averaged approximately $1.84 below the HH index during the second quarter, before the cost of transportation. The remainder of the DJ Basin gas is sold slightly above the CIG index price.

Gas Marketing. In December 2007, we entered into a second long-term (ten year) firm transportation contract for our Colorado natural gas production. This contract is for 25,000 MMBtu/D on the REX pipeline for gas production in the Piceance basin. We pay a demand charge for this capacity and our own production did not fill that capacity. In order to maximize our firm transportation capacity, we bought our partners' share of the gas produced in the Piceance at the market rate for that area. We then used our excess transportation to move this gas to where it was eventually sold. The net of our gas marketing revenue and our gas marketing expense in the Statements of Income is $.7 million in the six month period ended June 30, 2008. We expect our production will reach our firm transportation contract volume during 2009.

Oil Contracts. Utah - In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. The refiner has increased its total capacity to 5,000 Bbl/D as provided in our contract. As operator we deliver all produced volumes under our sales contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Gross oil production averaged approximately 4,000 BOE/D in the quarter ended June 30, 2008. The differential under the contract, which includes transportation and gravity adjustments, is linked to WTI and would range from $20 to $30 per barrel at WTI prices between $80 and $120. This contract provides us an outlet to sell all of our current oil production in the Uinta basin.

Hedging. See Note 4 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 cost-effective production of heavy oil in California. We sell our electricity to utilities under standard offer contracts based on "avoided cost" or SRAC pricing approved by the California Public Utilities Commission (CPUC) and under which our revenues are currently linked to the cost of natural gas. Natural gas index prices are the primary determinant of our electricity sales price based on the current pricing formula under these contracts. The correlation between electricity sales and natural gas prices allows us to manage our cost of producing steam more effectively.

In 2007, our electricity operations improved partially from the lower cost of our firm transportation natural gas compared to California prices which are used to determine our electricity payment. We purchase and transport 12,000 MMBtu/D on the Kern River Pipeline under our firm transportation contract and use this gas to produce conventional and cogeneration steam in the Midway-Sunset field. The differential between Rocky Mountain gas prices and Southern California Border prices increased during 2007 allowing us to purchase a portion of our gas at a discount to the Southern California Border price. As our electricity revenue is linked to Southern California Border prices, the fuel we purchased at lower Rocky Mountain prices was the primary contributor to the increase in our electricity margin in 2007. We purchased approximately 38,000 MMBtu/D as fuel for use in our cogeneration facilities in the year ended December 31, 2007. Rockies natural gas differentials have stabilized near their historical levels and we do not expect to have significant positive electricity margins in 2008. We expect to have small gains or losses on electricity on a quarterly basis which depends on seasonality as we receive improved pricing during the summer months. On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes the way SRAC energy prices will be determined for existing and new Standard Offer (SO) contracts and revises the capacity prices paid under current SO1 contracts. Based on our preliminary analysis, we do not believe that the proposed pricing changes will materially affect us in 2008.

The following table is for the three months ended:

	June 30, 2008	June 30, 2007	March 31, 2008
Electricity			
Revenues (in millions)	$ 17.0	$ 13.9	$ 15.9
Operating costs (in millions)	$ 15.5	$ 11.1	$ 16.4
Electric power produced - MWh/D	1,919	2,060	2,152
Electric power sold - MWh/D	1,724	1,819	1,959
Average sales price/MWh	$ 108.21	$ 84.13	$ 90.48
Fuel gas cost/MMBtu (including transportation)	$ 10.01	$ 6.46	$ 7.94

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)		
	June 30, 2008	June 30, 2007	March 31, 2008	June 30, 2008	June 30, 2007	March 31, 2008
Operating costs – oil and gas production	$ 20.91	$ 14.44	$ 16.30	$ 55,185	$ 35,725	$ 41,629
Production taxes	2.83	1.67	2.34	7,481	4,139	5,967
DD&A – oil and gas production	11.02	9.45	10.60	29,073	23,397	27,076
G&A	4.23	3.90	4.46	11,160	9,651	11,383
Interest expense	1.50	2.01	1.46	3,951	4,976	3,738
Total	$ 40.49	$ 31.47	$ 35.16	$ 106,850	$ 77,888	$ 89,793

Our total operating costs, production taxes, DD&A, G&A and interest expenses for the three months ended June 30, 2008, stated on a unit-of-production basis, increased 29% over the three months ended June 30, 2007 and increased –– 15% as compared to the three months ended March 31, 2008. The changes were primarily related to the following items:

- Operating costs: The majority of the increase in our operating costs was due to higher steam costs resulting from higher fuel costs. The following table presents steam information:

	June 30, 2008 (2Q08)	June 30, 2007 (2Q07)	2Q08 to 2Q07 Change	March 31, 2008 (1Q08)	2Q08 to 1Q08 Change
Average volume of steam injected (Bbl/D)	97,853	84,032	16%	91,326	7%
Fuel gas cost/MMBtu (including transportation)	$ 10.01	$ 6.46	55%	$ 7.94	26%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	27,382	22,559	21%	21,634	27%

Our total cost to purchase fuel for our steam operations increased by $2.07 per MMBtu or 26% in the three months ended June 2008 compared to the three months ended March 2008 as the SoCal border natural gas price increased over this time period. We consumed an additional 5,750 MMBtu/D in the second quarter of 2008 when compared to the first quarter of 2008 primarily related to increased conventional steam generation consumption and seasonal changes in the price received for our electricity which is used to allocate our cogeneration fuel gas volumes between electricity costs and steam costs. The increase in natural gas prices and our overall consumption accounted for approximately $10 million of the $13.6 million increase in operating costs between the first and second quarters of 2008. We plan to increase our fuel gas consumption by 4,000 MMBtu/D in the fourth quarter of 2008 as we add additional steam generation capacity at Poso Creek and the Diatomite.

During 2008, we generally expect a small change in our net income due to a change in natural gas prices as an increase in our steam costs is offset by revenue from our gas production and payments under our hedges. However, our gas long position can be impacted by volatility in the differential between the SoCal border price where we purchase the majority of our natural gas for steam generation and the Rockies prices at which we sell our produced volumes. Our realized price from the sale of natural gas increased $1.21/Mcf from the first quarter of 2008 as compared to the second quarter of 2008 while the cost of fuel purchased to generate steam and electricity increased $2.07/MMBtu over the same period.

- Production taxes: Our production taxes have increased compared to the second quarter of 2007 and the first quarter of 2008 as commodity prices and thus the values of our oil and natural gas has increased. Severance taxes paid in Utah and Colorado, are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. We expect production taxes to track oil and gas prices generally.

- Depreciation, depletion and amortization: DD&A increased per BOE by 17% and 4% in the second quarter of 2008 as compared to the second quarter of 2007 and as compared to the first quarter of 2008, respectively, due to an increase in the contribution of our development properties with higher drilling and leasehold acquisition costs, which is in line with our expectations.

- General and administrative: Approximately 70% of our G&A is related to compensation. The primary reason for the increase in G&A during the second quarter of 2008 as compared to the second quarter of 2007 was primarily due to an increase in the number of employees from 243 as of June 30, 2007 to 274 as of June 30, 2008.

- Interest expense: Our total outstanding borrowings were approximately $511 million at June 30, 2008 compared to $475 million and $455 million at June 30, 2007 and March 31, 2008, respectively. For the three months ended June 30, 2008, $4 million of interest cost has been capitalized and we expect to capitalize approximately $20 million of interest cost during the full year of 2008.

Estimated 2008 and Actual Six Months Ended June 30, 2008 and 2007 Oil and Gas Operating, G&A and Interest Expenses. We estimate our average 2008 production volume will range between 32,500 BOE/D and 33,500 BOE/D. Based on actual first six months and the remainder of 2008 at NYMEX WTI crude oil price of $100 per barrel and NYMEX HH natural gas price of $10.00 per MMBtu, we expect our expenses to be within the following ranges:

	Anticipated range in 2008 per BOE	Six months ended June 30, 2008	Six months ended June 30, 2007
Operating costs-oil and gas production (1)	$ 18.50 to 20.50	$ 18.64	$ 14.55
Production taxes	2.20 to 2.70	2.59	1.67
DD&A – oil and gas production	10.00 to 11.00	10.81	8.84
G&A	4.00 to 4.50	4.34	4.19
Interest expense	1.50 to 2.00	1.48	1.94
Total	$ 36.20 to 40.70	$ 37.86	$ 31.19

(1) We expect operating costs to increase in 2008 as compared to 2007 due to higher projected natural gas costs.

Our total operating costs, production taxes, DD&A, G&A and interest expenses for the six months ended June 30, 2008, stated on a unit-of-production basis, increased 21% over the six months ended June 30, 2007. The changes were primarily related to the following items:

- Operating costs: The majority of the increase in our operating costs was due to higher steam costs resulting from higher fuel costs. The following table presents steam information:

Six months ended June 30, 2008	Six months ended June 30, 2007	Change

Average volume of steam injected (Bbl/D)	94,589	85,076	11%
Fuel gas cost/MMBtu (including transportation)	$ 8.98	$ 6.58	37%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	24,536	21,022	17%

Our total cost to purchase fuel for our steam operations increased by $2.40 per MMBtu or 37% in the six months ended June 2008 compared to the six months ended June 2007 as the SoCal border natural gas price increased over this time period. We consumed an additional 3,510 MMBtus per day in the first six months of 2008 when compared to the first six months of 2007 primarily related to increased conventional steam generation consumption and seasonal changes in the price received for our electricity which is used to allocate our cogeneration fuel gas volumes.

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- Production taxes: Production taxes per BOE in the six months ended June 30, 2008 were 55% higher than the comparable period in 2007 as commodity prices and thus the values of our oil and natural gas has increased. Severance taxes paid in Utah and Colorado, are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. We expect production taxes to track oil and gas prices generally.

  - Depreciation, depletion and amortization: DD&A per BOE were 22% higher in the six months ended June 30, 2008 compared to the same period in the prior year due to an increase in the contribution of our development properties with higher drilling and leasehold acquisition costs, which is in line with our expectations.

- General and administrative: G&A per BOE increased by 4% in the six months ended June 30, 2007 compared to the same period in the prior year due to additional staffing and higher overall compensation costs associated with our growth activities.

  - Interest expense: Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, was approximately $511 million at June 30, 2008 compared to approximately $475 million at June 30, 2007. For the six months ended June 30, 2008, $8 million of interest cost has been capitalized.

Royalties. The price sensitive royalty that burdens our Formax property in the South Midway Sunset field has changed. We previously paid a royalty equal to 75% of the amount of the heavy oil posted above a price of $16.11. This price escalates at 2% annually. Effective January 1, 2008, the royalty rate is reduced from 75% to 53% as long as we maintain a minimum steam injection level, which we expect to meet, that reduces over time. Current net production from this property is approximately 2,300 Bbl/.

Dry Hole, Abandonment, impairment and exploration. In the first six months of 2008, we recorded a total of $7.6 million in dry hole, abandonment, impairment and exploration expense. Charges of $2.7 million and $2.6 million were recorded during the first and second quarters of 2008, respectively for technical difficulties that were encountered on four wells in the Piceance basin before reaching total depth. These holes were abandoned in favor of drilling to the same bottom hole location by drilling new wells. In addition, $2.3 million of exploration expense was recorded for exploration activities which were primarily 3-D seismic activity in the DJ basin.

Income Taxes. We experienced an effective tax rate of 37% and 39% in the three months ended June 30, 2008 and June 30, 2007, respectively. The lower rate in the second quarter of 2008 when compared to the same period in the prior year reflects changes in our state income apportionment which includes the projected income from our East Texas acquisition. Our rate differs from the combined federal and state statutory tax rate (net of the federal benefit), primarily due to certain business incentives. See Note 6 to the unaudited condensed financial statements.

Development, Exploitation and Exploration Activity. We drilled 120 gross (112 net) wells during the second quarter of 2008. As of June 30, 2008, we have 4 rigs drilling on our properties under long-term contracts and 4 more under short term contracts.

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

Three months ended June 30, 2008		Six months ended June 30, 2008
Gross Wells	Net Wells	

			Gross Wells	Net Wells
S. Midway	34	34	57	57
N. Midway	33	33	69	69
S. Cal	4	4	25	25
Piceance	20	12	39	21
Uinta	20	20	29	29
DJ	9	9	46	39
Totals	120	112	265	240

Properties

We have six asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including diatomite (N. Midway), Southern California including Poso Creek and Placerita (S. Cal), Piceance, Uinta and DJ.

S. Midway – During the three months ended June 30, 2008, production averaged approximately 9,100 Bbl/D compared to approximately 9,700 Bbl/D and 9,200 Bbl/D during the three month periods ended June 30, 2007 and March 31, 2008, respectively. We will invest $31 million on our S. Midway properties in 2008 to drill additional deeper horizontal wells along the cold, unswept flanks of the reservoir. Additional vertical wells will also be drilled to provide steam support for these horizontal wells. Sixteen horizontal wells plus the vertical steam support wells have been drilled and are performing as expected. We plan to drill the remaining six horizontal wells during the last half of the year. In 2008, we also began developing the Monarch reservoir on our Ethel D property. We drilled 24 wells in the Monarch in the first six months of the year and production averaged 900 Bbl/D using cyclic steam injection. We believe that production can be further enhanced through a steamflood and we will be expanding the pilot we began in 2007 later this year.

N. Midway – During the three months ended June 30, 2008, production from the area averaged approximately 2,600 Bbl/D compared to approximately 2,100 Bbl/D and 2,400 Bbl/D during the three month periods ended June 30, 2007 and March 31, 2008, respectively. In October 2007, we embarked on a full-scale, continuous development program of the Diatomite and we expect to drill non-stop over the next four years. Over 83 new producers have been drilled since October 2007. We are bringing these wells on production as the necessary infrastructure is installed to steam and produce these wells. We will nearly triple our producing well count this year from 80 wells at the end of 2007 to approximately 240 wells by year end 2008 and increase our steam generation capacity from 10,000 BSPD at the end of 2007 to 25,000 BSPD by the end of 2008. The additional wells, steam and supporting infrastructure should enable us to increase production of the Diatomite which averaged 1,700 BOE/D during the second quarter of 2008 to over 3,000 BOE/D by year end 2008. Additionally, we have drilled 6 delineation wells on the northern portion of our property and have identified significant additional resource potential that we will be evaluating during the remainder of the year.

S. Cal – During the three months ended June 30, 2008, production averaged approximately 5,300 Bbl/D compared to approximately 4,100 Bbl/D and 4,800 Bbl/D during the three month periods ended June 30, 2007 and March 31, 2008, respectively. This year’s plans at Poso Creek call for further expansion including the addition of a fourth steam generator, which we brought on line in February, drilling 28 producers and expanding the steam flood. As of June 2008, all 28 planned producers have been drilled and Poso Creek production is currently over 3,300 BOE/D. During the remainder of 2008, additional steam injectors will be drilled and a fifth steam generator will be installed to further increase our production from this asset.

Piceance – During the three months ended June 30, 2008, production from the Piceance basin averaged 16.6 MMcf/D. Of the Berry operated wells, we drilled 18 gross wells (12 net) during the second quarter of 2008. We are currently drilling our 36th well of the year and the 108th well since we acquired our original Piceance basin acreage in early 2006. We continue to operate four drilling rigs and see further efficiencies with repeated drilling times of 12 to 15 days for a mesa well. Late in the second quarter of 2008, we began realizing increased production as we moved into the summer completion season with current production now over 22 MMcf/D. Initial production rates from these wells have been in line with our expectations.

Uinta – Average daily production during the three months ended June 30, 2008 from all Uinta basin assets was approximately 6,100 net BOE/D. During the three months ended June 30, 2008, we accelerated our drilling program with an additional rig but plan to return to a one rig program for the remainder of 2008. The development at Brundage Canyon continues to be focused on drilling high potential areas in the core of the field where we drilled 20 wells in the second quarter of 2008. Evaluating the waterflood feasibility at Brundage Canyon has progressed and we have begun the permitting process, with first injection expected by year end 2008. Late in the second quarter of 2008, we further delineated the Ashley Forest by drilling two wells under our current environmental approvals and we anticipate drilling four to six additional wells during the last half of 2008. We continue to optimize and pace our Uinta drilling program while the Ashley Forest Development EIS progresses towards its anticipated approval in early 2009.

DJ – During the three months ended June 30, 2008, we drilled 8 successful gross Niobrara development wells in Yuma County, Colorado, with a 100% success rate. Average daily production in the DJ basin for the three months ended June 30, 2008 was 19.6 net MMcf/D and we had $.3 million of exploration expense in the second quarter related to our seismic surveys. During the second quarter we completed the interpretation of an additional 75 square miles of 3-D seismic that we acquired over the winter and expect to replenish our low risk repeatable drilling inventory.

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, production rates and operating expenses have been the primary reason for changes in our cash flow from operating activities.

We had a senior unsecured revolving bank credit facility agreement (the Agreement) with a banking syndicate through June 30, 2011. The Agreement was a revolving credit facility for up to $750 million with a borrowing base as of June 30, 2008 of $600 million. As of June 30, 2008, we had total borrowings under the Agreement and Line of Credit of $311 million and $200 million under our senior subordinated ten year notes.

On July 15, 2008, we entered into a five-year amended and restated credit agreement with Wells Fargo Bank, N.A as administrative agent and other lenders. The secured revolving credit facility amends and restates the Company's previous credit agreement dated as of April 28, 2006, as amended. The Credit Agreement is a $1.5 billion revolving facility with an initial borrowing base of $1 billion. On July 15, 2008, we borrowed approximately $594 million under the Credit Agreement to pay the remaining consideration due in the East Texas acquisition. As of July 15, 2008, we had approximately $75 million available to be drawn under our $1 billion credit facility. This agreement matures on July 15, 2013. In conjunction with securing our credit facility we also secured our Line of Credit.

Additionally, we entered into a commitment letter with certain lenders to execute a $100 million senior unsecured revolving credit facility. The execution of definitive documentation of the unsecured credit facility is subject to completion of due diligence by the Lenders and is expected to occur no later than July 31, 2008. The unsecured credit facility is expected to mature on December 31, 2008 and will have usual and customary conditions, representations and warranties.

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. Acquisitions are typically debt financed. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows.

In 2008, we had an original capital program of approximately $295 million, excluding acquisitions. The capital development program was increased by $75 million during the second quarter of 2008 in conjunction with our Texas acquisition to a total of $370 million. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. Excess cash generated from operations is expected to be applied toward acquisitions, debt reduction or other corporate purposes.

Our 2008 expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2008, we plan to invest approximately $118 million, or 32%, in our heavy crude oil assets, $175 million, in our base natural gas and light oil assets and $75 million in the development of our East Texas acquisition. Capital expenditures, excluding property acquisitions, totaled $95 million and $172 million during the three and six months ended June 30, 2008, respectively.

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. Crude oil and gas sales in the three months ended June 30, 2008 were 13% higher than the three months ended March 31, 2008 resulting from a 6% increase in oil prices (see graphs on page 14) and a 16% increase in gas prices (see graphs on page 14) and production increases in oil and natural gas. Proceeds from the sale of our Prairie Star assets are $1.8 million in the Statements of Cash Flows and the gain from that sale is $.4 million in the Statements of Income in the six months ended June 30, 2008.

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 arrangement. 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):

	June 30, 2008 (2Q08)	June 30, 2007 (2Q07)	2Q08 to 2Q07 Change	March 31, 2008 (1Q08)	2Q08 to 1Q08 Change
Average production (BOE/D)	29,000	27,195	7%	28,066	3%
	$ 69.77	$ 45.43	54%	$ 60.43	15%

Average oil and gas sales prices, per BOE after hedging					
Net cash provided by operating activities (1)	$107	$ 81	32%	$ 87	23%
Working capital	$ (225)	$ (39)	(464)%	$ (123)	(79)%
Sales of oil and gas	$185	$113	64%	$ 164	13%
Total debt	$511	$475	8%	$ 455	12%
Capital expenditures, including acquisitions and deposits on acquisitions	$154	$131	18%	$ 77	100%
Dividends paid	$3.4	$ 3.4	-%	$ 3.3	3%

(1) The change in the book overdraft line in the Statements of Cash Flows is classified as an operating activity to reflect the use of these funds in operations, rather than their prior year classification as a financing activity.

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Contractual Obligations. Our contractual obligations as of June 30, 2008 are as follows (in millions):

		Total	2008	2009	2010	2011	2012	Thereafter
Total debt and interest	$	687.4	$ 14.3	$ 28.5	$ 28.6	$ 333.5	$ 16.5	$ 266.0
Abandonment obligations		40.0	.7	1.4	1.4	1.5	1.5	33.5
Operating lease obligations		17.0	1.2	2.2	2.1	2.1	2.1	7.3
Drilling and rig obligations		55.9	12.8	16.3	7.4	19.4	-	-
Firm natural gas transportation contracts		165.7	7.7	19.5	19.5	19.5	19.1	80.4
Total	$	966.0	$ 36.7	$ 67.9	$ 59.0	$ 376.0	$ 39.2	$ 387.2

Drilling obligations - Under our June 2006 joint venture agreement in the Piceance basin we are required to have 120 wells drilled by February 2011 to avoid penalties of $.2 million per well or a maximum of $24 million. As of June 30, 2008 we have drilled 23 of these wells and we expect to meet our obligation to have the remaining wells drilled by February 2011.

Other Obligations - We adopted the provisions of FIN No. 48 on January 1, 2007 and recognized no material adjustment to retained earnings. As of June 30, 2008, we had a gross liability for uncertain tax benefits of $12.9 million of which $10.5 million, if recognized, would affect the effective tax rate.

In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007, as provided in our contract. The refiner has increased its total purchase capacity to 5,000 Bbl/D as provided in our contract. The differential under the contract, which includes transportation and gravity adjustments, is linked to WTI and would range from $20 to $30 per barrel at WTI prices between $80 and $120. Gross oil production averaged approximately 4,000 BOE/D in the quarter ended June 30, 2008.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 4 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, we enter into crude oil and natural gas hedge contracts from time to time. 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 some commodity price increases. In California, we benefit from lower natural gas pricing as we are a consumer of natural gas in our operations and elsewhere, we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate in accordance with policy established by our board of directors.

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 various index prices.

The following table summarizes our hedge position as of June 30, 2008:

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		
Full year 2008	10,000	$47.50 / $70.00	3rd Quarter 2008	19,000	$1.40
Full year 2009	10,000	$47.50 / $70.00	4th Quarter 2008	21,000	$1.46
Full year 2009	295	$80.00 / $91.00			
Full year 2010	1,000	$60.00 / $80.00	Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
Full year 2010	1,000	$55.00 / $76.20	1st Quarter 2009	15,400	$1.17
Full year 2010	1,000	$55.00 / $77.75	2nd Quarter 2009	15,400	$1.12
Full year 2010	1,000	$55.00 / $77.70	3rd Quarter 2009	15,400	$0.97
Full year 2010	1,000	$55.00 / $83.10	4th Quarter 2009	15,400	$1.05
Full year 2010	1,000	$60.00 / $75.00			
Full year 2010	1,000	$65.50 / $78.50	Natural Gas Sales (NYMEX HH) Swaps		
Full year 2010	280	$80.00 / $90.00	3rd Quarter 2008	16,200	$8.04
Full year 2011	270	$80.00 / $90.00	4th Quarter 2008	16,200	$8.04
			Full year 2009	15,400	$8.50
Crude Oil Sales (NYMEX WTI) Swaps					
Full year 2008	335	$92.00	Natural Gas Sales (NYMEX HH) Collars		Floor/Ceiling Prices
Full year 2009	240	$71.50	3rd Quarter 2008	2,800	$7.50 / $8.50
			4th Quarter 2008	4,800	$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 our floor prices which range from $47.50 to $80.00 per barrel while still participating in any oil price increase up to the ceiling prices which range from $70.00 to $91.00 per barrel on the volumes indicated above, and if 2) gas prices decline below our floor prices which range from $7.50 to $8.00 per MMBtu while still participating in any gas price increase up to the ceiling prices, which range from $8.40 to $9.50 per MMBtu on the respective volumes. 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, including certain basis differentials. 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 our credit facility.

While we have designated our 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 crude oil price differential may be determined to be ineffective. Likewise, we may have some ineffectiveness in our natural gas hedges due to the movement of HH pricing as compared to actual sales points. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income (Loss). If the differential were to change significantly, it is possible that our hedges, when mark-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to our net income. The mark-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity.

In November 2007 we entered into natural gas swaps at an index that did not correlate with the index at which the gas is sold and therefore those 2008 gas hedges are not highly effective. In January 2008 we entered into natural gas swaps which were not highly effective at inception, so we subsequently entered into basis swaps and established effectiveness at that time. Thus, we recognized unrealized net losses of approximately $.1 million and $.8 million in the Statements of Income under the caption “Commodity derivatives” for the three months ended June 30, 2008 and for the six months ended June 30, 2008, respectively.

Additionally, in 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility. These interest rate swaps have been designated as cash flow hedges.

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities. Irrespective of the unrealized gains reflected in Other Comprehensive Income (Loss), the ultimate impact to net income over the life of the hedges will reflect the actual settlement values. All of these hedges have historically been deemed to be cash flow hedges and are booked at fair value.

Based on average NYMEX futures prices as of June 30, 2008 (WTI $139.01; HH $12.82) for the term of our hedges we would expect to make pretax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	June 30, 2008 NYMEX Futures	Impact of percent change in futures prices on pretax future cash (payments) and receipts -20%	-10%	+ 10%	+ 20%
Average WTI Futures Price (2008 – 2011)	$ 139.01	$ 111.21	$ 125.11	$ 152.91	$ 166.82
Average HH Futures Price (2008 – 2009)	12.82	10.26	11.55	14.11	15.39
Crude Oil gain/(loss) (in millions)	$ (604.8)	$ (350.0)	$ (477.4)	$ (732.2)	$ (859.6)
Natural Gas gain/(loss) (in millions)	(30.2)	(10.1)	(22.1)	(46.1)	(58.1)
Total	$ (635.0)	$ (360.1)	$ (499.5)	$ (778.3)	$ (917.7)
Net pretax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2008 (WTI $140.73; HH $13.54)	$ (157.4)	$ (91.2)	$ (126.2)	$ (196.2)	$ (231.2)
2009 (WTI $140.88; HH $12.47)	(291.1)	(168.8)	(229.9)	(352.3)	(413.5)
2010 (WTI $138.51)	(181.9)	(98.2)	(140.1)	(223.8)	(265.6)
2011 (WTI $136.79)	(4.6)	(1.9)	(3.3)	(6.0)	(7.4)
Total	$ (635.0)	$ (360.1)	$ (499.5)	$ (778.3)	$ (917.7)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued $200 million of 8.25% senior subordinated notes due 2016 in a public offering. Total long-term debt outstanding including our short-term Line of Credit, at June 30, 2008 was $311 million. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 1.0% to 1.75%, with the exception of the $100 million of principal for which we have hedged the interest rate at approximately 5.5% plus the credit facility's margin through June 30, 2011. Based on June 30, 2008 credit facility borrowings, a 1% change in interest rates would have an annual $–––1.3 million after tax impact on our financial statements.

Item 4. Controls and Procedures

As of June 30, 2008, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended.

Based on their evaluation as of June 30, 2008, our 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 by us 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 that occurred during the three months ended June 30, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

Forward Looking Statements

“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 “plan,” “will,” “intend,” “continue,” “target(s),” “expect,” “achieve,” “future,” “may,” “could,” “goal(s),” “anticipate,” or other comparable words or ph the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results and will not complete such actions on the timetable indicated.
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 14 of our Form 10-K/A filed with the Securities and Exchange Commission, under the heading “Risk Factors” and all material changes are updated in Part II, Item 1A within this Form 10-Q.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings
None.

Item 1A. Risk Factors
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
At the annual meeting, which was held at the Four Points Sheraton Hotel, Bakersfield, California, on May 14, 2008, ten incumbent directors were re-elected. The results of voting as reported by the inspector of elections are noted below:

1. There were 44,408,401 shares of our capital stock issued, outstanding and generally entitled to vote as of the record date, March 17, 2008.

2. There were present at the meeting, in person or by proxy, the holders of 41,055,321 shares, representing 92.45% of the total number of shares outstanding and entitled to vote at the meeting, such percentage representing a quorum.

PROPOSAL ONE: Election of ten Directors

NOMINEE	VOTES CAST FOR	PERCENTAGE OF QUORUM VOTES CAST	AUTHORITY WITHHELD
Joseph H. Bryant	40,792,588	99.36%	262,733
Ralph B. Busch, III	40,623,215	98.95%	432,106
William E. Bush, Jr	40,615,502	98.93%	439,819
Stephen L. Cropper	40,894,899	99.61%	160,422
J. Herbert Gaul, Jr.	40,894,023	99.61%	161,298
Robert F. Heinemann	40,610,077	98.92%	445,244
Thomas J. Jamieson	40,615,672	98.93%	439,649
J. Frank Keller	40,790,643	99.36%	264,678
Ronald J. Robinson	40,793,243	99.36%	262,078
Martin H. Young, Jr	40,901,003	99.62%	154,318

Percentages are based on the shares represented and voting at the meeting in person or by proxy.

PROPOSAL TWO: Ratification of the appointment of PricewaterhouseCoopers LLP as the Independent Registered Public Accounting Firm (Independent Auditors).

For	Against	Abstentions	Broker Non-Votes

Shares	40,705,860	348,595	866	-

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No.	Description of Exhibit
10.1	Amended and Restated Credit Agreement, dated as of July 15, 2008 by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions.
10.2	Purchase and Sale Agreement Between O'Brien Resources, LLC, Sepco II, LLC, Liberty Energy, LLC, Crow Horizons Company and O'Benco II LP collectively as Seller and Berry Petroleum Company as Purchaser, dated as of June 10, 2008.
10.3	Overriding Royalty Purchase Agreement between O'Brien Resources, LLC, as Seller, and Berry Petroleum Company, as Purchaser, dated as of June 10, 2008.
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.

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/ Shawn M. Canaday
Shawn M. Canaday
Vice President and Controller
(Principal Accounting Officer)

Date: July 25, 2008