BERRY PETROLEUM CO
Form 10-Q
August 01, 2007

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, 2007**
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 July 19, 2007, the registrant had 42,310,379 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 19, 2007 all of which is held by an affiliate of the registrant.

1

BERRY PETROLEUM COMPANY
SECOND QUARTER 2007 FORM 10-Q
TABLE OF CONTENTS

BERRY PETROLEUM COMPANY
Unaudited Condensed Balance Sheets
(In Thousands, Except Share Information)

	June 30, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 315	$ 416
Short-term investments	664	665
Accounts receivable	73,818	67,905
Deferred income taxes	7,713	-
Fair value of derivatives	7,224	7,349
Assets held for sale	7,000	8,870
Prepaid expenses and other	11,360	13,604
Total current assets	108,094	98,809
Oil and gas properties (successful efforts basis), buildings and equipment, net	1,193,252	1,080,631
Fair value of derivatives	368	2,356
Other assets	16,117	17,201
	$ 1,317,831	$ 1,198,997
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 77,495	$ 69,914
Property acquisition payable	-	54,400
Revenue and royalties payable	24,606	45,845
Accrued liabilities	16,765	20,415
Line of credit	9,500	16,000
Fair value of derivatives	25,875	8,084
Other current liabilities	2,781	745
Total current liabilities	157,022	215,403
Long-term liabilities:		
Deferred income taxes	127,385	103,515
Long-term debt	465,000	390,000
Abandonment obligation	30,287	26,135
Unearned revenue	830	1,437
Other long-term liabilities	9,028	-
Fair value of derivatives	48,925	34,807
	681,455	555,894
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; 42,297,729 shares issued and outstanding (42,098,551 in 2006)	423	421
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899)	18	18
Capital in excess of par value	57,755	50,166
Accumulated other comprehensive loss	(39,985)	(19,977)
Retained earnings	461,143	397,072

Total shareholders' equity	479,354	427,700
	$ 1,317,831	$ 1,198,997

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

3

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Three Month Periods Ended June 30, 2007 and 2006
(In Thousands, Except Per Share Data)

	Three months ended June 30, 2007		2006	
REVENUES AND OTHER INCOME ITEMS				
Sales of oil and gas	$	113,426	$	110,641
Sales of electricity		13,867		11,715
Gain on sale of assets		50,400		-
Interest and other income, net		1,536		803
		179,229		123,159
EXPENSES				
Operating costs – oil and gas production		35,725		27,074
Operating costs – electricity generation		11,083		10,626
Production taxes		4,139		3,373
Depreciation, depletion & amortization - oil and gas production		23,397		16,263
Depreciation, depletion & amortization - electricity generation		961		807
General and administrative		9,651		7,877
Interest		4,976		2,460
Commodity derivatives		-		(5,563)
Dry hole, abandonment, impairment and exploration		3,519		3,045
		93,451		65,962
Income before income taxes		85,778		57,197
Provision for income taxes		33,821		22,994
Net income	$	51,957	$	34,203
Basic net income per share	$	1.18	$	.78
Diluted net income per share	$	1.16	$	.76
Dividends per share	$	.075	$	.065
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)		44,029		44,053
Effect of dilutive securities:				
Equity based compensation		751		785
Director deferred compensation		115		101
Weighted average number of shares of capital stock used to calculate diluted net income per share		44,895		44,939

Unaudited Condensed Statements of Comprehensive Income
Three Month Periods Ended June 30, 2007 and 2006
(In Thousands)

Net income	$	51,957	$	34,203
Unrealized gains (losses) on derivatives, net of income taxes of ($4,395) and ($11,414), respectively		(6,593)		(17,121)
Reclassification of realized (gains) losses included in net income net of income taxes of ($697) and ($1,178), respectively		(1,045)		(1,767)
Comprehensive income	$	44,319	$	15,315

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, 2007 and 2006
(In Thousands, Except Per Share Data)

	Six months ended June 30, 2007	2006
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 215,200	$ 212,575
Sales of electricity	28,463	26,884
Gain on sale of assets	50,398	-
Interest and other income, net	2,647	1,296
	296,708	240,755
EXPENSES		
Operating costs – oil and gas production	69,335	52,813
Operating costs – electricity generation	25,254	24,958
Production taxes	7,954	6,606
Depreciation, depletion & amortization - oil and gas production	42,122	29,359
Depreciation, depletion & amortization - electricity generation	1,723	1,701
General and administrative	19,958	16,192
Interest	9,267	4,038
Commodity derivatives	-	(736)
Dry hole, abandonment, impairment and exploration	4,168	10,543
	179,781	145,474
Income before income taxes	116,927	95,281
Provision for income taxes	46,115	37,827
Net income	$ 70,812	$ 57,454
Basic net income per share	$ 1.61	$ 1.31
Diluted net income per share	$ 1.58	$ 1.28
Dividends per share	$ .15	$ .13
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	43,973	44,020
Effect of dilutive securities:		
Equity based compensation	668	836
Director deferred compensation	113	99
Weighted average number of shares of capital stock used to calculate diluted net income per share	44,754	44,955

Unaudited Condensed Statements of Comprehensive Income
Six Month Periods Ended June 30, 2007 and 2006
(In Thousands)

Net income	$	70,812	$	57,454
Unrealized gains (losses) on derivatives, net of income taxes of ($12,457) and ($26,965), respectively		(18,685)		(40,448)
Reclassification of realized (gains) losses included in net income net of income taxes of ($882) and ($2,356), respectively		(1,323)		(3,534)
Comprehensive income	$	50,804	$	13,472

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

5

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Six Month Periods Ended June 30, 2007 and 2006
(In Thousands)

	Six months ended June 30, 2007	2006
Cash flows from operating activities:		
Net income	$ 70,812	$ 57,454
Depreciation, depletion and amortization	43,845	31,060
Dry hole and impairment	3,547	6,782
Abandonment	(625)	(407)
Commodity derivatives	675	(674)
Stock-based compensation expense, net of taxes	3,779	2,199
Deferred income taxes, net	39,695	25,068
Gain on sale of oil and gas properties	(50,398)	-
Other, net	415	(64)
Increase in current assets other than cash, cash equivalents and short-term investments	(5,066)	(18,596)
Decrease in current liabilities other than book overdraft, line of credit, property acquisition payable and fair value of derivatives	(14,635)	(18,726)
Net cash provided by operating activities	92,044	84,096
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(148,452)	(103,939)
Property acquisitions	(56,106)	(161,600)
Additions to vehicles, drilling rigs and other fixed assets	(2,052)	(5,892)
Proceeds from sale of asset	61,258	-
Capitalized interest and other	(8,365)	-
Net cash used in investing activities	(153,717)	(271,431)
Cash flows from financing activities:		
Proceeds from issuance of line of credit	203,800	155,000
Payment of line of credit	(210,300)	(143,000)
Proceeds from issuance of long-term debt	179,300	235,250
Payment of long-term debt	(104,300)	(61,250)
Dividends paid	(6,678)	(5,726)
Change in book overdraft	(4,060)	14,242
Repurchase of shares of common stock	-	(12,771)
Proceeds from stock option exercises	2,595	1,685
Excess tax benefit and other	1,215	2,541
Net cash provided by financing activities	61,572	185,971
Net decrease in cash and cash equivalents	(101)	(1,364)
Cash and cash equivalents at beginning of year	416	1,990
Cash and cash equivalents at end of period	$ 315	$ 626
Supplemental non-cash activity:		
Decrease in fair value of derivatives:		
Current (net of income taxes of $6,845 and $9,015, respectively)	$ (10,267)	$ (13,622)
	(9,741)	(30,360)

Non-current (net of income taxes of $6,494 and $19,775, respectively)				
Net decrease to accumulated other comprehensive income	$	(20,008)	$	(43,982)

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, 2007 and December 31, 2006 and results of operations for the three and six month periods ended June 30, 2007 and 2006 and cash flows for the six month periods ended June 30, 2007 and 2006 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, 2006 financial statements. The December 31, 2006 Form 10-K and the March 31, 2007 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.

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, 2007, December 31, 2006 and June 30, 2006 is $13.1 million, $17.2 million and $16.2 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

In December 2004, Statement of Financial Accounting Standards (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. As a result, we adopted this statement beginning January 1, 2006. This standard requires us 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. Accordingly, the adoption of SFAS No. 123(R) using the modified prospective method did not have a material impact on our condensed financial statements for the year ended December 31, 2006. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation* effective January 1, 2004. The modified prospective method was selected as described in SFAS No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. Under this method, we 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.

2. Recent Accounting Developments

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. This interpretation requires that realization of an uncertain income tax position must be "more likely than not" (i.e. greater than 50% likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, this interpretation prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. This interpretation also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. This interpretation is effective for fiscal years beginning after December 15, 2006, and we adopted this interpretation in the first quarter of 2007. See Note 5.

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. SFAS No. 157 will become effective for our fiscal year beginning January 1, 2008, and we are currently assessing the potential impact of this statement on our 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* was issued by the Securities and Exchange Commission. 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 was adopted at December 31, 2006. The adoption of SAB No. 108 had no effect on our financial position or on the results of our operations.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

2. Recent Accounting Developments (Cont'd)

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity's election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement is effective beginning January 1, 2008 and we are currently assessing the potential impact of this statement on our financial statements.

3. Hedging

The related cash flow impact of all of our hedges are reflected in cash flows from operating activities. At June 30, 2007, our net fair value of derivatives liability was $67.2 million as compared to $33.2 million at December 31, 2006. At June 30, 2007, Accumulated Other Comprehensive Loss consisted of $40 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, 2007. Deferred net losses recorded in Accumulated Other Comprehensive Loss at June 30, 2007 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts. Our liability is primarily related to the time value of the underlying instruments and based on current prices the amount expected to be reclassified to earnings over the next 12 months is approximately $5 million before tax.

As of February 28, 2007, we converted 2,000 Bbl/D of our 2007 oil collars beginning on March 1, 2007 to a swap with a strike price of $60 West Texas Intermediate (WTI). Additionally, we entered into the following oil swaps and oil collars during the six months ended June 30, 2007:

- oil swaps for 1,000 Bbl/D at $64.55 from July 2007 through December 2007
- oil collars for 1,000 Bbl/D at $60 floor and $75 ceiling prices for calendar year 2010
- oil collars for 1,000 Bbl/D at $65.15 floor and $75 ceiling prices for calendar year 2010

These hedges have been designated as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.*

4. 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. In 2007, we reassessed our estimate as costs have increased due to demand for related services, resulting in an increase in the ARO balance at quarter end.

Under SFAS 143, the following table summarizes the change in abandonment obligation for the six months ended June 30, 2007 (in thousands):

Beginning balance at January 1	$	26,135
Liabilities incurred		1,274
Liabilities settled		(1,566)
Revisions in estimated liabilities		3,272
Accretion expense		1,172
Ending balance at June 30	$	30,287

8

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

5. Income Taxes

The effective tax rate was 39% for the second quarter of 2007 compared to 39% for the first quarter of 2007 and 40% for the second quarter of 2006.

In June 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. The Interpretation addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

We adopted the provisions of FIN No. 48 on January 1, 2007 and recognized no material adjustment to retained earnings. As of the date of adoption, we had a gross liability for uncertain tax benefits of $14.6 million of which $10.8 million, if recognized, would affect the effective tax rate. We recognize potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. As of January 1, 2007, we had accrued approximately $.9 million of interest related to our uncertain tax positions.

We have not had any material changes to our unrecognized tax benefits since adoption, nor do we anticipate significant changes to the total amount of unrecognized tax benefits within the next 12 months.

As of January 1, 2007, we remain subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction:	Tax Years Subject to Exam:
Federal	2003 – 2006
California	2002 – 2006
Colorado	2002 – 2006
Utah	2003 – 2006

6. Long-term and Short-term Obligations

Long-term debt

In October 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. The net proceeds from the offering were used to 1) repay approximately $145 million of borrowings under the bank credit facility, which were $170 million as of the issuance date after the application of this payment, and 2) approximately $50 million was used to pay the November 1, 2006 installment under the joint venture agreement to develop properties in the Piceance basin.

In April 2006, we completed a new unsecured five year bank credit facility 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 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*. Effective May 2007 and in accordance with the existing Agreement, the bank syndicate agreed to increase the borrowing base by $50 million to $550 million.

The total outstanding debt at June 30, 2007 under the credit facility and the short-term Line of Credit, described below, was $265 million and $10 million, respectively, leaving $275 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 a commitment fee of .25% to .375% on the unused portion of the credit facility annually.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

6. Long-term and Short-term Obligations (Cont'd)

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. Our Notes covenants limit debt to the greater of $750 million or 40% of Adjusted Consolidated Net Tangible Assets (as defined). Additionally, as long as the interest coverage ratio (as defined) is met, we may incur additional debt. We were in compliance with all such covenants as of June 30, 2007. The weighted average interest rate on the long-term outstanding credit facility borrowings at June 30, 2007 was 6.4%.

Short-term debt
In November 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, 2007 the outstanding balance under this Line of Credit was $10 million. 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, 2007 was 6.2%.

7. 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 accrued. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not require substantial accruals. 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.

On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly Corporation (Holly) for a portion of our Uinta basin crude oil. Under the agreement, Holly began purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase total purchased volumes to 5,000 Bbl/D through June 30, 2013. During the term of the contract, the minimum number of delivered units ("base daily volume") is 3,200 Bbl/D increasing to 5,000 Bbl/D upon the certified completion of the refinery upgrade. Holly may, but is not obligated to, purchase volumes in excess of the base daily volumes.

8. Asset Impairment

During the three month period ended June 30, 2007, a charge of $2.9 million was recorded to dry hole, abandonment, impairment and exploration expense to reduce our carrying value of the Bakken asset in the Williston Basin, North Dakota from $9.9 million to $7 million, which we believe approximates fair value as of June 30, 2007 based on available information.

9. Assets Held for Sale

On May 11, 2007 we sold our non-core West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million with approximately $50 million gain on the sale.

Net oil and gas properties and equipment classified as held for sale is $7 million for the Bakken asset and $8.9 million for the Montalvo asset at June 30, 2007 and December 31, 2006, respectively, in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. The carrying value of the West Montalvo properties of $8.9 million included in assets held for sale at December 31, 2006 was used to compute the $50 million gain on sale of assets for the quarter ended June 30, 2007. Assets held for sale of $7 million at June 30, 2007 represents the carrying value of the Bakken asset. As of June 30, 2007, we are pursuing the divestment of our Bakken asset, which during the first six months of 2007 was producing less than 10 BOE per day.

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, 2007 and 2006 and our financial condition, liquidity and capital resources as of June 30, 2007. 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.

Overview. Our mission is 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.

- Production averaged 27,195 BOE/D, up 10% from the second quarter of 2006 and 7% from the first quarter of 2007
- Restored Uinta basin production to approximately 6,300 BOE/D during the second quarter of 2007 from a low of 3,800 BOE/D in January 2007
- Increased production at Midway-Sunset diatomite by 50% to an average 900 BOE/D in the second quarter of 2007 from 600 BOE/D in the first quarter of 2007 resulting from our more aggressive steam cycling and new well fracturing techniques
- Completed and tied into gathering systems 10 gross (six net) Piceance basin operated wells which increased Piceance net production to 8.3 MMcf/D
- Accelerated Poso Creek development by drilling 49 wells and installing an additional steam generator
- Sold Montalvo properties with proceeds at approximately $61 million before adjustments

Notable Items and Expectations for the Third Quarter of 2007.

- Focusing on reducing drilling costs of our operated Piceance mesa wells and we expect to complete over 20 gross (11 net) Piceance wells and while targeting third quarter average net production of 12.5 MMcf/D
- Production at Midway-Sunset diatomite is approaching 1,000 BOE/D while the steam to oil ratio is improving and we will begin drilling the next 50 well expansion
- Accelerating Poso Creek and Ethel D development by drilling 19 wells
- Drilling 11 additional infill horizontal wells at South Midway-Sunset
- Companywide production is projected to average between 27,000 BOE/D and 28,000 BOE/D for the third quarter of 2007

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

	June 30, 2007 (2Q07)	June 30, 2006 (2Q06)	2Q07 to 2Q06 Change	March 31, 2007 (1Q07)	2Q07 to 1Q07 Change
Sales of oil	$ 94.4	$ 95.0	(1%)	$ 80.9	17%
Sales of gas	19.0	15.7	21%	20.9	(9%)
Total sales of oil and gas	$ 113.4	$ 110.7	2%	$ 101.8	11%
Sales of electricity	13.9	11.7	19%	14.6	(5%)
Gain on sale of assets	50.4	-	-%	-	-%
Interest and other income, net	1.5	.8	88%	1.1	36%
Total revenues and other income	$ 179.2	$ 123.2	45%	$ 117.5	53%
Net income	$ 52.0	$ 34.2	52%	$ 18.9	175%
Net income per share (diluted)	$ 1.16	$ .76	53%	$ .42	176%

Our revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. Our production for the second quarter of 2007 averaged 27,195 BOE/D, which was up 10% from the second quarter of 2006, and an increase of 7% from the first quarter of 2007. Our production increased by over 1,700 BOE/D in the second quarter over the first quarter due primarily to higher production from our properties in the Uinta basin and Piceance basin, which increased by 22% and 28%, respectively. Our average production for the six months ended June 30, 2007 was 26,332 BOE/D, which was up 9% from the same period last year. While production continues to improve, based on the timing of the increases from our projects we are forecasting average production of between 26,700 BOE/D and 28,000 BOE/D for the full year of 2007.

Crude oil sales in the three months ended June 30, 2007 were 17% higher than the three months ended March 31, 2007 resulting from price increases of 12% and production increases of 4%. Gas sales in the three months ended June 30, 2007 were 9% lower than the three months ended March 31, 2007 resulting from a price decline of 23%, partially offset by production increases of 15%.

On May 11, 2007 we sold our non-core West Montalvo assets, in Ventura County, California. The sales price was approximately $61 million, netting us a pre-tax gain on sale of assets of approximately $50 million. In addition, during the second quarter we paid the third and final installment of approximately $54 million for the North Parachute Ranch property located in the Piceance basin.

In the second quarter of 2007, we incurred an impairment charge of $2.9 million to dry hole, abandonment, impairment and exploration expense to reduce the carrying value of our Bakken asset in the Williston Basin, North Dakota from $9.9 million to $7 million that reflects estimated market value. We plan to divest of this asset in the near future.

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

	June 30, 2007	%	June 30, 2006	%	March 31, 2007	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	16,129	59	15,532	63	16,140	63
Light Oil Production (Bbl/D)	4,034	15	4,061	16	3,233	13
Total Oil Production (Bbl/D)	20,163	74	19,593	79	19,373	76
Natural Gas Production (Mcf/D)	42,193	26	31,047	21	36,704	24
Total (BOE/D)	27,195	100	24,768	100	25,490	100
Per BOE:						
Average sales price before hedging	$ 44.72		$ 52.46		$ 43.62	
Average sales price after hedging	45.43		49.75		43.84	
Oil, per Bbl:						
Average WTI price	$ 65.02		$ 70.72		$ 58.23	
Price sensitive royalties	(4.20)		(5.66)		(3.74)	
Quality differential and other	(9.24)		(8.49)		(8.78)	
Crude oil hedges	(.52)		(3.38)		.03	
Average oil sales price after hedging	$ 51.06		$ 53.19		$ 45.74	
Gas, per MMBtu:						
Average Henry Hub price	$ 7.65		$ 6.65		$ 7.18	
Natural gas hedges	.75		-		.13	
Location, quality differentials and other	(3.29)		(1.06)		(.70)	
Average gas sales price after hedging	$ 5.11		$ 5.59		$ 6.61	

The following table is for the six months ended:

		June 30, 2007	%		June 30, 2006	%
Oil and Gas						
Heavy Oil Production (Bbl/D)		16,112	61		15,470	64
Light Oil Production (Bbl/D)		3,643	14		3,684	15
Total Oil Production (Bbl/D)		19,755	75		19,154	79
Natural Gas Production (Mcf/D)		39,463	25		29,784	21
Total (BOE/D)		26,332	100		24,118	100
Per BOE:						
Average sales price before hedging	$	44.25		$	51.08	
Average sales price after hedging		44.72			48.92	
Oil, per Bbl:						
Average WTI price	$	61.68		$	67.13	
Price sensitive royalties		(3.97)			(5.52)	
Quality differential and other		(9.01)			(7.49)	
Crude oil hedges		(.24)			(2.72)	
Average oil sales price after hedging	$	48.46		$	51.40	
Gas, per MMBtu:						
Average Henry Hub price	$	7.42		$	7.28	
Natural gas hedges		.46			(.01)	
Location, quality differentials and other		(2.04)			(1.14)	
Average gas sales price after hedging	$	5.84		$	6.13	

Gas Basis Differential. Natural gas prices in the Rockies continue to be volatile due to various factors, including takeaway pipeline capacity, supply volumes, and regional demand issues. We expect the basis differential between Henry Hub (HH) and Colorado Interstate Gas (CIG) to narrow upon the startup of the Rockies Express Pipeline (REX) which is anticipated in 2008. We have contracted 10,000 MMBtu/D on this pipeline to provide assurance of gas delivery. The CIG basis differential per MMBtu, based upon first-of-month values, averaged $3.78 below HH and ranged from $2.92 to $4.37 below HH in the second quarter. Although related to CIG, the actual basin price varies. Gas from the Piceance basin was slightly below the CIG price while Uinta basin gas sold for approximately $0.45 below CIG pricing. DJ Basin gas is priced using one of two indices. For that portion of the production with firm transportation on either the Cheyenne Plains Pipeline or the KMIGT pipeline, pricing is based upon the Panhandle Eastern Pipeline (PEPL) index which averaged about $1.07 below the HH index before the cost of transportation is considered. The remainder of the DJ Basin gas is sold slightly above the CIG index price.

Oil Contracts. Utah – During the second quarter of 2007, the marketing of our Uinta crude has significantly improved. Our Utah crude oil is paraffinic crude and can be processed efficiently by only a limited number of refineries. We are currently able to secure short-term contracts which, along with long-term contracts, allowed us to produce at full capacity. As of June 30, 2007, our Utah light crude oil is sold under multiple long-term and short-term contracts with different purchasers for varying prices. In some cases the price is tied to field postings and in other contracts the price is based upon a percentage of average of the NYMEX WTI prices. As operator we deliver all produced volumes pursuant to these contracts. Our net volumes from our Brundage Canyon properties currently approximate 80% of the total gross volumes. Overall, during the second quarter, the average selling price for Uinta crude was $50.69 per Bbl before transportation costs.

On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly for a portion of our Uinta basin crude oil. Under the agreement, Holly began purchasing 3,200 Bbl/D beginning July 1, 2007. Holly took delivery of approximately 1,000 Bbl/D and 1,500 Bbl/D in the first and second quarters of 2007, respectively, which stabilized our realized sales price and reduced our transportation costs. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation, is a fixed percentage of WTI and approximates our expected field posted price of $13 to $16 below WTI. This contract provides the pricing assurance we need to proceed with the long-term development of our Uinta basin assets. We may adjust our capital expenditures in the Uinta basin due to various factors, including the timing of refinery demand for the Uinta basin barrels and the actual or expected change in our realized price.

Hedging. See Note 3 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 for the three months ended June 30, 2007 were up from the three months ended June 30, 2006 due to 24% increase in electricity prices and 8% increase in fuel gas cost, respectively. Conversely, revenue and operating costs in the three months ended June 30, 2007 were down from the three months ended March 31, 2007 due to lower natural gas prices. The following table is for the three months ended:

	June 30, 2007	June 30, 2006	March 31, 2007
Electricity			
Revenues (in millions)	$ 13.9	$ 11.7	$ 14.6
Operating costs (in millions)	$ 11.1	$ 10.6	$ 14.2
Electric power produced - MWh/D	2,060	2,023	2,117
Electric power sold - MWh/D	1,819	1,827	1,914
Average sales price/MWh	$ 84.13	$ 67.88	$ 81.08
Fuel gas cost/MMBtu (including transportation)	$ 6.46	$ 6.00	$ 6.70

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, 2007	June 30, 2006	March 31, 2007	June 30, 2007	June 30, 2006	March 31, 2007
Operating costs – oil and gas production	$ 14.44	$ 12.01	$ 14.65	$ 35,725	$ 27,074	$ 33,610
Production taxes	1.67	1.50	1.66	4,139	3,373	3,815
DD&A – oil and gas production	9.45	7.22	8.16	23,397	16,263	18,725
G&A	3.90	3.49	4.49	9,651	7,877	10,307
Interest expense	2.01	1.09	1.87	4,976	2,460	4,292
Total	$ 31.47	$ 25.31	$ 30.83	$ 77,888	$ 57,047	$ 70,749

Our total operating costs, production taxes, DD&A, G&A and interest expenses for the three months ended June 30, 2007, stated on a unit-of-production basis, increased 24% over the three months ended June 30, 2006 and increased 2% over the three months ended March 31, 2007. The changes were primarily related to the following items:

- Operating costs: Operating costs per BOE in the second quarter of 2007 were 20% higher than the second quarter of 2006 primarily due to an increase in steam costs, contract labor, well servicing, chemicals and transportation, compression and gathering costs. Operating costs per BOE were 1% lower in the second quarter of 2007 as compared to the first quarter of 2007 due to a 7% increase in production volume partially offset by higher steam costs, contract labor and well servicing. Cost pressures do remain, but we are working to offset them with improved efficiencies. The cost of our steaming operations on our heavy oil properties in California varies depending on the cost of natural gas used as fuel and the volume of steam injected. The following table presents steam information:

	June 30, 2007 (2Q07)	June 30, 2006 (2Q06)	2Q07 to 2Q06 Change	March 31, 2007 (1Q07)	2Q07 to 1Q07 Change
Average volume of steam injected (Bbl/D)	84,032	78,322	7%	86,132	(2%)
Fuel gas cost/MMBtu (including transportation)	$6.46	$ 6.00	8%	$ 6.70	(4%)

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. Based on current plans, we are targeting average steam injection of approximately 90,000 to 95,000 barrels of steam per day (BSPD) during the last six months of 2007. 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 2006 as the value of our oil and natural gas assets 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. In California, our production is burdened with ad valorem taxes on our total proved reserves. We expect production taxes, in general, to correlate with the underlying commodity price.

- Depreciation, depletion and amortization: DD&A per BOE were 31% higher in the three months ended June 30, 2007 compared to the same period in the prior year due to an increase in capital spending over the last year and particularly more extensive development in fields with higher drilling costs and leasehold acquisition costs. Our capital program is also experiencing cost pressures in contract labor and for goods and services commensurate with other energy developers. As these costs increase, our DD&A rates per BOE will also increase.

- General and administrative: G&A per BOE increased by 12% in the second quarter of 2007 compared to the second quarter of 2006. Approximately 73% of our G&A is compensation or compensation related costs. To remain competitive in workforce compensation and achieve our growth goals, compensation or compensation related costs increased significantly due to additional staffing, higher compensation levels, bonuses, stock compensation and benefit costs. G&A per BOE was 13% lower in the second quarter of 2007 as compared to the first quarter of 2007 due to a 7% increase in production volume and higher compensation and related taxes in the first quarter.

- Interest expense: Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, was $475 million at June 30, 2007 compared to $273 million at June 30, 2006. Our average borrowings increased since June 30, 2006 as a result of our capital expenditure program and due to payments of $153 million to purchase the North Parachute Ranch property located in the Piceance basin. Beginning in 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 until the remainder of our probable reserves have been recategorized to proved developed reserves. For the quarter ended June 30, 2007, $4 million has been capitalized and we expect to capitalize approximately $20 million of interest cost during the full year of 2007.

Estimated 2007 and Actual Six Months Ended June 30, 2007 and 2006 Oil and Gas Operating, G&A and Interest Expenses.

	Anticipated range In 2007 per BOE	Six months ended June 30, 2007	Six months ended June 30, 2006
Operating costs-oil and gas production *(1)*	$ 14.50 to 15.50	$ 14.55	$ 12.10
Production taxes	1.50 to 2.00	1.67	1.51
DD&A – oil and gas production	8.50 to 9.50	8.84	6.73
G&A	3.75 to 4.25	4.19	3.71
Interest expense	1.50 to 2.00	1.94	.92
Total	$ 29.25 to 33.25	$ 31.19	$ 24.97

(1) Assuming natural gas prices of approximately NYMEX HH $7.50 MMBtu, we plan to inject approximately 15% greater steam levels in 2007 compared to 2006 levels.

Income Taxes. See Note 5 to the unaudited condensed financial statements. Our effective tax rate will be similar in 2007 as compared to 2006. We experienced an effective tax rate in the three months ended June 30, 2007 of 39%, which is in line with our projections.

Development, Exploitation and Exploration Activity. We drilled 123 gross (88 net) wells during the second quarter of 2007, realizing a success rate of 98 percent. Management is closely monitoring the capital development program in relation to estimated cash flows and expects to expend capital in the $250 million to $280 million range, excluding acquisitions, during 2007. As of June 30, 2007, we have five rigs drilling on our properties under long-term contracts and have one more rig scheduled to begin in the third quarter of 2007.

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

	Three months ended June 30, 2007		Six months ended June 30, 2007	
	Gross Wells	Net Wells	Gross Wells	Net Wells
SMWSS	4	4	24	24
NMWSS	-	-	11	11
Socal	49	49	67	67
Piceance	31	8	49	13
Uinta	13	13	28	26
DJ *(1)*	26	14	68	35
Totals	**123**	**88**	**247**	**176**

(1) Includes 1 gross well (.5 net well) that was a dry hole in the first quarter of 2007 in Yuma County, Colorado and 3 gross wells (1.6 net wells) that were dry holes in the second quarter of 2007 in Niobrara .

Production

California's three asset teams are South Midway-Sunset (SMWSS, which has been realigned to include Ethel D), North Midway-Sunset (NMWSS, which includes diatomite) and Southern California (Socal, which includes Poso Creek and Placerita). The Rocky Mountain/Mid-Continent region's three asset teams are Piceance, Uinta and DJ basins.

SMWSS, San Joaquin Valley Basin (SJVB)– During the three months ended June 30, 2007, production averaged approximately 9,700 Bbl/D compared to approximately 10,800 Bbl/D and 9,900 Bbl/D during the three month periods ended June 30, 2006 and March 31, 2007, respectively. We completed 3 horizontal infill wells during the three months ending June 30, 2007 and we plan to drill 11 more horizontal infill wells in the third quarter. Increased production from these activities is expected to slow the natural decline.

NMWSS, SJVB– Our Midway-Sunset properties, including our diatomite project, are performing as expected. During the three months ended June 30, 2007, production from the NMWSS area averaged approximately 2,000 Bbl/D up from approximately 800 Bbl/D and 1,600 Bbl/D during the three month periods ended June 30, 2006 and March 31, 2007, respectively.

Production from the diatomite project has now improved to over 1,000 Bbl/D and is expected to increase as we begin the first phase of our "fairway" development in the third quarter of 2007. Our focus in the second quarter was to increase production through more aggressive steam cycling and new well fracturing techniques. We will begin a 50-well drilling program in the latter part of the third quarter along with installing the necessary infrastructure (steam generation equipment, dehydration facilities, pipeline corridors, etc.).

Socal, SJVB and Los Angeles Basin–During the three months ended June 30, 2007, production averaged approximately 5,200 Bbl/D up from approximately 3,200 Bbl/D and 4,800 Bbl/D during the three month periods ended June 30, 2006 and March 31, 2007, respectively.

Poso Creek is performing solidly above plan due to strong steam flood performance and our infill drilling. Production has increased to over 1,800 Bbl/D from less than 50 Bbl/D when we acquired the property in 2003. We are accelerating development by infill drilling over 70 wells this year and expanding the steam drive by 14 patterns. Through the second quarter of 2007 we have drilled 49 infill producers and installed a third steam generator. Production is expected to continue to improve as these wells are cyclically steamed, the additional steam flood patterns are brought on line and the balance of the infill wells are drilled and completed.

Piceance Basin, Colorado – During the second quarter, production from the Piceance averaged 8.3 MMcf/D, an increase of 31% over the first quarter. On the Berry operated wells, we completed 10 wells (six net) during the second quarter and completed an additional six wells (four net) in July. Reservoir performance continues to meet our expectations and with recent well connections, production as of July 25, 2007 is above 11 MMcf/D. An additional 14 wells (seven net) are forecasted to be drilled and connected by the end of the third quarter, and we anticipate production will approximate 12.5 MMcf/D for the third quarter of 2007.

We currently have four drilling rigs operating in the basin and expect to maintain this level for the remainder of the year. Further progress has been made to lower the days required to drill wells and we continue to expand the infrastructure needed to support our operations. The Garden Gulch mountain and extension roads were completed in the second quarter and have greatly improved access to our Garden Gulch Plateau acreage. Construction on the water delivery system to supply our drilling and stimulation program is near completion and expected to be operational in the third quarter. We are also pursuing opportunities to acquire additional firm transportation for future sales out of this region.

Uinta Basin, Utah – Our 2007 capital is directed at additional Brundage Canyon 40-acre development wells, drilling the Ashley Forest extension to the south of Brundage Canyon, continued Lake Canyon assessment and drilling 20-acre infill wells in Brundage Canyon. During the second quarter, we drilled 13 net wells in Brundage Canyon. Well performance results continue to be positive and preliminary results from five 20-acre pilot wells indicate favorable opportunities for additional increased density drilling in the field.

Average daily production during the second quarter from all Uinta basin assets was approximately 6,400 net BOE/D. The production exit rate in the second quarter was approximately 6,900 net BOE/D. We continue to have one drilling rig operating in the basin. Our current oil marketing arrangements provide us the ability to sell all of our crude oil production in the Uinta basin.

Post winter season access to our Ashley Forest acreage and Lake Canyon area opened up in May 2007. Our third quarter drilling activity will focus on continued efforts to extend Brundage Canyon success south into the Ashley Forest and continue our assessment of Lake Canyon potential to the west of Brundage. In support of our third quarter plans, we have 16 approved drilling permits and a 4 well drilling commitment in Lake Canyon along with 12 approved permits in the Ashley Forest. An Ashley Forest well that was drilled in the second quarter of 2007 is providing encouraging initial oil production results.

DJ Basin– Our second quarter activity in the DJ basin has focused on drilling 23 successful Niobrara development wells in Yuma County, Colorado. Average daily production in the DJ for the second quarter was 18,706 net MMcf/D. Berry's Yuma County Niobrara projects provide sustainable and steady cash flow resulting from low capital development costs, modest production declines (5% exponential after an 18-month hyperbolic decline) and long-life reserves.

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 senior unsecured revolving credit facility to increase our maximum credit amount under the facility to $750 million and increased our current borrowing base to $500 million. In the second quarter of 2007, we increased our current borrowing base to $550 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 $145 million.

As of June 30, 2007, we had total borrowings under the senior unsecured revolving credit facility and senior unsecured money market line of credit of $275 million and $200 million under our senior subordinated ten year notes.

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, drilling outcomes and/or changes in commodity prices that influence our decision to change capital expenditures to closely match operating cash flows. Excess cash generated from operations is expected to be applied toward capital expenditures, debt reduction or other corporate purposes.

Our 2007 expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2007, we plan to invest up to approximately $176 million, or 66%, in our Rocky Mountain/Mid-Continent region assets, and up to $91 million, or 34%, in our California assets.

Management is closely monitoring the capital development program in relation to estimated cash flows and expects to expend capital in the $250 million to $280 million range, excluding acquisitions, during 2007. The capital development program may be revised due to timing of crude deliveries out of the Uinta basin, equipment availability, permitting and/or changes in our internal development plans. Capital expenditures, excluding property acquisitions, totaled $76 million and $151 million during the three months ended June 30, 2007 and six months ended June 30, 2007, respectively.

On May 11, 2007 we completed the sale of our non-core West Montalvo assets in Ventura County, California. The sales price was approximately $61 million and we transferred the properties in the second quarter of 2007. Production from the property was approximately 700 BOE/D, which is less than 3% of current production and, as of December 31, 2006, the property had 7 million BOE of proved reserves which is less than 5% of the 2006 year end total of 150 million BOE. In addition, during the second quarter we paid the third and final installment of approximately $54 million for the North Parachute Ranch property located in the Piceance basin.

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, 2007 were 11% higher than the three months ended March 31, 2007 resulting from an 11% increase in oil price (see graphs on page 12) and a 7% increase in production, partially offset by a 23% decline in gas prices (see graphs on page 12).

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 senior unsecured revolving 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, 2007 (2Q07)	June 30, 2006 (2Q06)	2Q07 to 2Q06 Change	March 31, 2007 (1Q07)	2Q07 to 1Q07 Change
Average production (BOE/D)	27,195	24,768	10%	25,490	7%
Average oil and gas sales prices, per BOE after hedging	$ 45.43	$ 49.75	(9%)	$ 43.84	4%
	$ 80	$ 59	36%	$ 12	567%

Net cash provided by operating activities					
Working capital, excluding line of credit	$ (39)	$ (38)	3%	$ (65)	(40%)
Sales of oil and gas	$ 113	$ 111	2%	$ 102	11%
Long-term debt, including line of credit	$ 475	$ 273	74%	$ 477	-%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 131	$ 65	102%	$ 76	72%
Dividends paid	$ 3.4	$ 2.9	17%	$ 3.3	3%

Contractual Obligations. Our contractual obligations as of June 30, 2007 are as follows (in millions):

	Total	2007	2008	2009	2010	2011	Thereafter
Long-term debt and interest	$ 706.4	$ 33.5	$ 33.5	$ 33.5	$ 33.5	$ 289.9	$ 282.5
Abandonment obligations	30.3	.8	.9	1.0	1.0	1.0	25.6
Operating lease obligations	13.2	.8	1.6	1.4	1.4	1.4	6.6
Drilling and rig obligations	92.6	18.5	29.2	42.7	2.2	-	-
Firm natural gas transportation contracts	71.4	2.4	7.5	8.5	8.7	8.7	35.6
Total	$ 913.9	$ 56.0	$ 72.7	$ 87.1	$ 46.8	$ 301.0	$ 350.3

Long-term debt and interest - Our credit facility borrowings and related interest of approximately 6.4% can be paid before its maturity date without significant penalty. Our 8.25% senior subordinated notes mature in November 2016, but are not redeemable until November 1, 2011 and are not redeemable without any premium until November 1, 2014.

Operating leases - We lease corporate and field offices in California, Colorado and Texas. We lease an airplane for business travel under a ten year operating lease beginning December 2006.

Drilling obligation - We intend to participate in the drilling of over 16 wells on our Lake Canyon prospect over the four year contract, which began in 2006. Our minimum expenditure obligation under our exploration and development agreement is $9.6 million. Also included above, under our June 2006 joint venture agreement in the Piceance basin, we must drill 120 wells by 2010 to avoid penalties of $.2 million per well or a maximum 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 for California operations. This 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 transportation contracts which provide us with physical access to interstate pipelines to move gas from our producing areas to markets.

On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly for a portion of our Uinta basin crude oil. Under the agreement, Holly began purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. During the term of the contract, the minimum number of delivered units (“base daily volume”) is 3,200 Bbl/D increasing to 5,000 Bbl/D upon the certified completion of the refinery upgrade. Holly may, but is not obligated to, purchase volumes in excess of the base daily volumes upon proper notification by us.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 3 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 any 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 CIG and Questar index prices, respectively.

The following table summarizes our hedge position as of June 30, 2007:

Term	Average Barrels Per Day	Floor/Ceiling Prices	Term	Average MMBtu Per Day	Floor/Ceiling Prices
Crude Oil Sales (NYMEX WTI) Collars			**Natural Gas Sales (NYMEX HH) Collars**		
Full year 2007	8,000	$47.50 / $70.00	3rd Quarter 2007	14,000	$8.00 / $9.10
Full year 2008	10,000	$47.50 / $70.00	4th Quarter 2007	15,000	$8.00 / $11.39
Full year 2009	10,000	$47.50 / $70.00	1st Quarter 2008	16,000	$8.00 / $15.65
Full year 2010	1,000	$60.00 / $80.00	2nd Quarter 2008	17,000	$7.50 / $8.40
Full year 2010	1,000	$55.00 / $76.20	3rd Quarter 2008	19,000	$7.50 / $8.50
Full year 2010	1,000	$55.00 / $77.75	4th Quarter 2008	21,000	$8.00 / $9.50
Full year 2010	1,000	$55.00 / $77.70			
Full year 2010	1,000	$55.00 / $83.10			
Full year 2010	1,000	$60.00 / $75.00			
Full year 2010	1,000	$65.15 / $75.00			
			Natural Gas Sales (NYMEX HH TO CIG)		
Swaps		Price	**Basis Swaps**		Price
3rd through 4th quarter 2007	1,000	$64.55	July 2007	14,000	$1.56
3rd through 4th quarter 2007	2,000	$60.00	August 2007	14,000	$1.51
			September 2007	14,000	$1.58
			October 2007	15,000	$1.63
			November & December 2007	15,000	$1.71
			1st Quarter 2008	16,000	$1.74
			2nd Quarter 2008	17,000	$1.43
			3rd Quarter 2008	19,000	$1.40
			4th Quarter 2008	21,000	$1.46

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 $78.95 per barrel on these volumes and if 2) 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 our senior unsecured revolving 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. While we believe that the differential will narrow and move closer toward its historical level over time, there are no assurances as to the movement in the differential. If the differential were to change significantly, it is possible that our hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to our net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity.

We 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 we recognized an unrealized net loss of approximately $4.8 million on the income statement under the caption “Commodity derivatives.”

We 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 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.

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, 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 with the marked-to-market valuations provided by external sources, based on prices that are actually quoted.

Based on NYMEX futures prices as of June 29, 2007, (WTI $72.01; HH $8.04) 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:

	June 29, 2007 NYMEX Futures	Impact of percent change in futures prices on earnings -20%	-10%	+ 10%	+ 20%
Average WTI Futures Price (2007 – 2010)	$ 72.01	$ 57.61	$ 64.81	$ 79.21	$ 86.41
Average HH Futures Price (2007 – 2008)	8.04	6.43	7.24	8.85	9.66
Crude Oil gain/(loss) (in millions)	$ (23.9)	$ 7.2	$ (1.1)	$ (96.0)	$ (179.7)
Natural Gas gain/(loss) (in millions)	4.9	15.4	8.1	1.9	(2.9)
Total	$ (19.0)	$ 22.6	$ 7.0	$ (94.1)	$ (182.6)
Net pre-tax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2007 (WTI $71.03; HH $7.33)	$ (1.4)	$ 11.6	$ 5.7	$ (17.1)	$ (32.2)
2008 (WTI $72.25; HH $8.41)	(8.6)	6.4	1.1	(36.7)	(67.1)
2009 (WTI $72.43)	(9.0)	-	-	(35.3)	(61.7)
2010 (WTI $71.85)	-	4.6	0.2	(5.0)	(21.6)
Total	$ (19.0)	$ 22.6	$ 7.0	$ (94.1)	$ (182.6)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. On October 24, 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, 2007 was $475 million. Interest on amounts borrowed under our revolving 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 a hedge in place to fix the interest rate at approximately 5.5% plus the senior unsecured revolving credit facility’s margin through June 30, 2011. Based on June 30, 2007 credit facility borrowings, a 1% change in interest rates would have an annual $1 million after tax impact on our financial statements.

Item 4. Controls and Procedures

As of June 30, 2007, we have carried out an evaluation under the supervision of, and with the participation of 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, 2007, 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 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 "plan," "will," "intend," "continue," "target(s)," "expect," "achieve," "future," "may," "could," "goal(s),", "forecast," "anticipate," or other comparable phrases, or the 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 15 of our Form 10-K 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 10-Q.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

None.

Item 1A. Risk Factors

We may not be able to deliver minimum crude oil volumes required by our sales contract. Production volumes from our Uinta properties over the next six years are uncertain and there is no assurance that we will be able to consistently meet the minimum requirement. On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly for a portion of our Uinta basin crude oil. Under the agreement, we began delivering 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. During the term of the contract, the minimum number of delivered units ("base daily volume") is 3,200 Bbl/D increasing to 5,000 Bbl/D upon the certified completion of the refinery upgrade.

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 16, 2007, ten incumbent directors were re-elected. The results of voting as reported by the inspector of elections are noted below:

1. There were 43,926,074 shares of our capital stock issued, outstanding and generally entitled to vote as of the record date, March 19, 2007.

2. There were present at the meeting, in person or by proxy, the holders of 40,931,241 shares, representing 93.18% 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	PERCENT OF QUORUM VOTES CAST	AUTHORITY WITHHELD
Joseph H. Bryant	40,677,589	99.38%	253,652
Ralph B. Busch, III	40,183,280	98.17%	747,961
William E. Bush, Jr.	40,182,365	98.17%	748,876
Stephen L. Cropper	40,700,544	99.44%	230,697
J. Herbert Gaul, Jr.	40,701,194	99.44%	230,047
Robert F. Heinemann	40,292,331	98.44%	638,910
Thomas J. Jamieson	40,312,798	98.49%	618,443
J. Frank Keller	40,669,480	99.36%	261,761
Ronald J. Robinson	40,657,630	99.83%	273,611
Martin H. Young, Jr.	40,705,746	99.45%	225,495

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	40,338,903	440,319	152,019	-

<u>Item 5. Other Information</u>

None.

<u>Item 6. Exhibits</u>

<u>Exhibit No</u>.	<u>Description of Exhibit</u>
10.1*	Purchase and sale agreement between the Company and Venoco, Inc. dated March 19, 2007 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2007, File No. 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.

* Portions of this exhibit have been omitted pursuant to a request for confidential treatment

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
Controller
(Principal Accounting Officer)

Date: August 1, 2007