Primoris Services Corp
Form 8-K
April 01, 2013

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported) **March 14, 2013**

PRIMORIS SERVICES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**001-34145**	**20-4743916**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

2100 McKinney Avenue, Suite 1500, Dallas, TX 75201

(Address of principal executive offices) (Zip Code)

Registrant s telephone number, including area code **(214) 740-5600**

Not Applicable

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

As used in this Current Report on Form 8-K, the terms we, us, our and the Company mean Primoris Services Corporation, a Delaware corporation, and our consolidated subsidiaries, taken together as a whole.

Item 1.01 Entry into a Material Definitive Agreement

Master Loan and Security Agreement with Banc of America Leasing & Capital, LLC

On March 14, 2013, Stellaris, LLC (Stellaris), a wholly owned subsidiary of the Company, entered into a Master Loan and Security Agreement (the BofA Agreement) with Banc of America Leasing & Capital, LLC (the Bank) for financing of equipment, pursuant to an equipment note. In connection with the transaction, Stellaris entered into the Addendum to Master Loan and Security Agreement (the Addendum), dated March 22, 2013 with the Bank, whereby certain of our subsidiaries have agreed to be obligated as co-borrowers for all amounts borrowed under the BofA Agreement. The Equipment Security Note (the Note), dated March 14, 2013, with the Bank for $16.12 million, was funded on March 25, 2013. The Note is secured by certain construction equipment as outlined in Exhibit A of the Note. The Note is payable in equal monthly installments over a seven year period. The principal amount of the Note bears interest at 2.18% per annum and may be prepaid subject to certain prepayment breakage fees. A copy of the agreements are attached to the Current Report on Form 8-K, with the BofA Agreement as Exhibit #10.1, the Addendum as Exhibit #10.2 and the Note as Exhibit #10.3.

Item 9.01. Financial Statements and Exhibits.

(d) Exhibits .

Exh. No.	Description
10.1	Master Loan and Security Agreement, dated March 14, 2013, by and among Stellaris, LLC and Banc of America Leasing & Capital, LLC.
10.2	Addendum to Master Loan and Security Agreement, dated March 22, 2013, by and among Stellaris LLC, ARB, Inc. James Construction Group, LLC, BTEX Materials, LLC, Miller Springs Materials, LLC, Primoris Energy Services Corporation and Banc of America Leasing & Capital, LLC.
10.3	Equipment Security Note, dated March 14, 2013, by and among Stellaris LLC, ARB, Inc. James Construction Group, LLC, Miller Springs Materials, LLC, Primoris Energy Services Corporation and Banc of America Leasing & Capital, LLC.

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 hereunto duly authorized.

PRIMORIS SERVICES CORPORATION

Date: April 1, 2013	By:	/s/ Peter J. Moerbeek	
		Name:	Peter J. Moerbeek
		Title:	Executive Vice President, Chief Financial Officer

EXHIBIT INDEX

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PART II.
OTHER INFORMATION

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

	September 30, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 59	$ 316
Short-term investments	65	58
Accounts receivable	145,701	117,038
Deferred income taxes	38,987	28,547
Fair value of derivatives	2,198	2,109
Assets held for sale	-	1,394
Prepaid expenses and other	19,432	11,557
Total current assets	206,442	161,019
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,196,322	1,275,091
Other assets	17,307	15,996
	$ 2,420,071	$ 1,452,106
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 150,750	$ 90,354
Revenue and royalties payable	35,779	47,181
Accrued liabilities	37,284	21,653
Line of credit	19,300	14,300
Income taxes payable	380	2,591
Fair value of derivatives	110,427	95,290
Total current liabilities	353,920	271,369
Long-term liabilities:		
Deferred income taxes	206,848	128,824
Long-term debt	1,109,300	445,000
Abandonment obligation	40,414	36,426
Unearned revenue	-	398
Other long-term liabilities	6,226	1,657
Fair value of derivatives	106,459	108,458
	1,469,247	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; 42,737,029 shares issued and outstanding (42,583,002 in 2007)	427	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	77,739	66,590
Accumulated other comprehensive loss	(130,361)	(120,704)
Retained earnings	649,081	513,645
Total shareholders' equity	596,904	459,974
	$ 2,420,071	$ 1,452,106

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

3

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

	Three months ended September 30, 2008	2007
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 207,863	$ 118,733
Sales of electricity	18,317	12,241
Gas marketing	13,284	-
Gain on sale of assets	95	1,418
Interest and other income, net	1,202	1,108
	240,761	133,500
EXPENSES		
Operating costs - oil and gas production	56,038	33,995
Operating costs - electricity generation	13,706	9,760
Production taxes	9,673	4,344
Depreciation, depletion & amortization - oil and gas production	40,440	23,356
Depreciation, depletion & amortization - electricity generation	646	938
Gas marketing	12,034	-
General and administrative	14,524	9,333
Interest	8,755	4,326
Commodity derivatives	(594)	-
Dry hole, abandonment, impairment and exploration	1,571	5,175
	156,793	91,227
Income before income taxes	83,968	42,273
Provision for income taxes	30,620	15,418
Net income	$ 53,348	$ 26,855
Basic net income per share	$ 1.20	$ .61
Diluted net income per share	$ 1.17	$ .60
Dividends per share	$ .075	$ .075
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share		
Effect of dilutive securities:	44,527	44,112
Equity based compensation	886	772
Director deferred compensation	128	118
Weighted average number of shares of capital stock used to calculate diluted net income per share	45,541	45,002

Unaudited Condensed Statements of Comprehensive Income
Three Month Periods Ended September 30, 2008 and 2007

	(In Thousands)	
Net income	$ 53,348	$ 26,855
Unrealized gains (losses) on derivatives, net of income taxes (benefits) of $144,881 and ($7,027), respectively	225,693	(10,541)
Reclassification of realized gains on derivatives included in net income, net of income taxes of $18,745 and $1,411, respectively	30,584	2,116
Comprehensive income	$ 309,625	$ 18,430

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

4

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

	Nine months ended September 30, 2008	2007
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 557,689	$ 333,933
Sales of electricity	51,223	40,704
Gas marketing	28,046	-
Gain on sale of assets	510	51,816
Interest and other income, net	4,095	3,754
	641,563	430,207
EXPENSES		
Operating costs - oil and gas production	152,852	103,330
Operating costs - electricity generation	45,620	35,014
Production taxes	23,121	12,297
Depreciation, depletion & amortization - oil and gas production	96,588	65,478
Depreciation, depletion & amortization - electricity generation	1,991	2,661
Gas marketing	26,087	-
General and administrative	37,067	29,291
Interest	16,444	13,593
Commodity derivatives	172	-
Dry hole, abandonment, impairment and exploration	9,162	9,342
	409,104	271,006
Income before income taxes	232,459	159,201
Provision for income taxes	86,939	61,534
Net income	$ 145,520	$ 97,667
Basic net income per share	$ 3.27	$ 2.22
Diluted net income per share	$ 3.20	$ 2.18
Dividends per share	$ .225	$ .225
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share	44,466	44,020
Effect of dilutive securities:		
Equity based compensation	914	701
Director deferred compensation	126	115
Weighted average number of shares of capital stock used to calculate diluted net income per share	45,506	44,836

Unaudited Condensed Statements of Comprehensive Income
Nine Month Periods Ended September 30, 2008 and 2007
(In Thousands)

Net income	$ 145,520	$ 97,667

Unrealized losses on derivatives, net of income tax benefits of $58,260 and $19,484, respectively	(95,055)	(29,226)
Reclassification of realized gains on derivatives included in net income, net of income taxes of $52,341 and $529, respectively	85,399	793
Comprehensive income	$ 135,864	$ 69,234

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

5

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

	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Cash flows from operating activities:		
Net income	$ 145,520	$ 97,667
Depreciation, depletion and amortization	98,579	68,139
Dry hole and impairment	6,858	8,725
Commodity derivatives	(180)	804
Stock-based compensation expense	6,653	5,437
Deferred income taxes	76,502	53,162
Unrealized loss on ineffective hedges	172	-
Gain on sale of oil and gas properties	(510)	(51,816)
Other, net	(1,500)	750
Change in book overdraft	3,935	(2,995)
Cash paid for abandonment	(3,957)	(660)
Increase in current assets other than cash and cash equivalents	(35,361)	(10,785)
Increase in current liabilities other than book overdraft, line of credit and fair value of derivatives	34,537	13,116
Net cash provided by operating activities	331,248	181,544
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(302,266)	(206,240)
Property acquisitions	(667,030)	(56,167)
Additions to vehicles, drilling rigs and other fixed assets	(4,146)	(2,944)
Proceeds from sale of assets	2,038	68,432
Capitalized interest	(15,461)	(13,160)
Net cash used in investing activities	(986,865)	(210,079)
Cash flows from financing activities:		
Proceeds from issuances on line of credit	308,000	285,150
Payments on line of credit	(303,000)	(296,650)
Proceeds from issuance of long-term debt	1,481,300	179,300
Payments on long-term debt	(817,000)	(134,300)
Debt issuance cost	(8,353)	-
Dividends paid	(10,084)	(10,036)
Proceeds from stock option exercises	2,834	3,051
Excess tax benefit and other	1,663	1,795
Net cash provided by financing activities	655,360	28,310
Net decrease in cash and cash equivalents	(257)	(225)
Cash and cash equivalents at beginning of year	316	416
Cash and cash equivalents at end of period	$ 59	$ 191

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 September 30, 2008 and December 31, 2007 and results of operations and comprehensive (loss) income and cash flows for the three month and nine month periods ended September 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 September 30, 2008 and December 31, 2007 is $11.7 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 by $10.5 million and reducing our royalties payable.

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.

2. Recent Accounting Developments

In September 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Positions (FSP) No. 133-1 and FIN 45-4 to amend FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, to require disclosures by sellers of credit derivatives, including credit derivatives embedded in a hybrid instrument. This FSP also amends FASB Interpretation No.45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, to require an additional disclosure about the current status of the payment/performance risk of a guarantee. Further, this FSP clarifies the FASB's intent about the effective date of FASB Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities. We do not expect the adoption of this FSP to have a material effect on our financial statements and related disclosures. This FSP is effective for financial statements issued for reporting periods (annual or interim) ending after November 15, 2008, with early application encouraged.

In December 2007, the 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 for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008.

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

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 non controlling 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, which has not yet occurred. 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.

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.

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

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

September 30, 2008 (in millions)	Total carrying value on the condensed Balance Sheet	Level 2	Level 3
Commodity derivatives	209.8	.9	208.9
Interest rate swaps	4.9	4.9	-
Total liabilities at fair value	214.7	5.8	208.9

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 September 30, 2008	Nine months ended September 30, 2008
Fair value, beginning of period	$ 569.6	$ 194.3
Total realized and unrealized gains and (losses) included in sales of oil and gas	(370.5)	31.1
Purchases, sales and settlements, net	9.8	(16.5)
Transfers in and/or out of Level 3	-	-
Fair value, September 30, 2008	$ 208.9	$ 208.9
Total unrealized gains and (losses) included in income related to financial assets and liabilities still on the condensed balance sheet at September 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.

4. Hedging

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At September 30, 2008, our net fair value of derivatives liability was $214.7 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 September 30, 2008, we expect to make hedge payments under the existing derivatives of $115.4 million during the next twelve months. At September 30, 2008, Accumulated Other Comprehensive Loss consisted of $130.4 million, net of tax, of unrealized losses from our crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at September 30, 2008. Deferred net losses recorded in Accumulated Other Comprehensive Loss at September 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.

9

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

These swaps were not highly effective at inception, so we subsequently entered into basis swaps and established effectiveness at that time. In 2007, we entered into natural gas swap contracts that were not highly effective. We recognized an unrealized net gain of approximately $.6 million and an unrealized net loss of $.2 million on the income statement under the caption Commodity derivatives in the three and nine months ended September 30, 2008, respectively.

We entered into the following oil hedges during the three months ended September 30, 2008:

Crude Oil Sales (NYMEX WTI) Collars	Average Barrels Per Day	Floor/Ceiling Prices	Deferred Premium Per Barrel
Full year 2009	1,000	$ 100.00 / $163.60	$ 1.00
Full year 2009	1,000	$ 100.00 / $150.30	$ -
Full year 2009	1,000	$ 100.00 / $160.00	$ 2.00
Full year 2009	1,000	$ 100.00 / $150.00	$ 0.63
Full year 2009	1,000	$ 100.00 / $157.48	$ -
Full year 2010	1,000	$ 100.00 / $161.10	$ 1.00
Full year 2010	1,000	$ 100.00 / $150.30	$ -
Full year 2010	1,000	$ 100.00 / $160.00	$ 2.00
Full year 2010	1,000	$ 100.00 / $150.00	$ 1.55
Full year 2010	1,000	$ 100.00 / $158.50	$ -

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

Our hedge contracts have been primarily executed with the counterparties that are party to our senior secured revolving credit facility. The credit rating of each of these counterparties is AA/Aa2 or better as of September 30, 2008.

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 nine months ended September 30, 2008 (in thousands):

Beginning balance at January 1	$	36,426
Liabilities incurred		3,490
Liabilities settled		(3,957)
Revisions in estimated liabilities		2,006
Accretion expense		2,449
Ending balance at September 30	$	40,414

6. Acquisitions and Dispositions

During the third quarter of 2008, Berry completed the acquisition of certain interests in natural gas producing properties on 4,500 net acres in Limestone and Harrison Counties of East Texas for $666 million cash including an initial purchase price of $622 million, and normal post closing adjustments of $44 million. See the pro forma discussion in Footnote 8 of these financial statements. As part of the acquisition we assumed commitments for drilling rig contracts and compressor rental agreements which approximate $30 million. Oil and gas properties increased $921 million or 72% from December 31, 2007 to September 30, 2008 primarily due to this acquisition. 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 nine month period ended September 30, 2008.

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

7. Dry Hole, Abandonment and Impairment

In the first nine months of 2008, we recorded a total of $9.2 million in dry hole, abandonment, impairment and exploration expense. Charges of $2.7 million, $2.6 million and $1.6 million were recorded during the first, second and third quarters of 2008, respectively, for technical difficulties that were encountered on five 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.

8. Pro Forma Results

On July 15, 2008, the Company acquired certain interests in natural gas producing properties on 4,500 net acres in Limestone and Harrison Counties in East Texas for $666 million cash (East Texas Acquisition) including an initial purchase price of $622 million, and normal post closing adjustments of $44 million.

The unaudited pro forma results presented below for the three and nine months ended September 30, 2008 and 2007 have been prepared to give effect to the East Texas Acquisition on the Company's results of operations under the purchase method of accounting as if it had been consummated on January 1, 2007. The unaudited pro forma results do not purport to represent the results of operations that actually would have occurred on such date or to project the Company's results of operations for any future date or period:

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Pro forma revenue	$ 253,112	$ 142,785	$ 694,269	$ 454,747
Pro forma income from operations	$ 91,082	$ 31,035	$ 239,235	$ 124,520
Pro forma net income	$ 57,427	$ 20,913	$ 150,423	$ 78,878
Pro forma basic earnings per share	$ 1.29	$ 0.47	$ 3.38	$ 1.79
Pro forma diluted earnings per share	$ 1.27	$ 0.46	$ 3.31	$ 1.76

The following is a preliminary calculation and allocation of purchase price to the East Texas Acquistion assets and liabilities based on their relative fair values:

Purchase price (in thousands):	As of September 30, 2008
Original purchase price	$ 622,356
Closing adjustments for property costs, and operating expenses in excess of revenues between the effective date and closing date	43,811
Total purchase price allocation	$ 666,167

Preliminary allocation of purchase price (in thousands):			
Oil and natural gas properties	$	651,803	(i)
Pipeline		17,288	
Total assets acquired		669,091	
Current liabilities		(1,569)	(ii)
Asset retirement obligation		(1,355)	
Net assets acquired	$	666,167	

(i) Determined by reserve analysis.

(ii) Accrual for royalties payable and transaction costs, which are primarily legal and accounting fees.

11

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

9. Income Taxes

The effective tax rate was 36.5% for the third quarter of 2008 compared to 36.8% for the second quarter of 2008 and 36.5% for the third quarter of 2007. Our estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences.

As of September 30, 2008, we had a gross liability for uncertain tax benefits of $11.9 million of which $9.6 million, if recognized, would affect the effective tax rate. There were no significant changes to the calculation since year end 2007. For the nine months ending September 30, 2008, we recognized a net tax benefit of approximately $0.9 million due to the closure of the 2004 federal tax year offset by additional FIN 48 accruals including interest.

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.

10. Debt Obligations

Short-term lines of credit
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. In conjunction with the amendment to our senior secured credit facility, on July 15, 2008, the Line of Credit was secured with oil and gas properties. At September 30, 2008 the outstanding balance under this Line of Credit was $19.3 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 September 30, 2008 was 5.35%.

In July, 2008, we completed a $100 million senior unsecured credit facility that was to mature on December 31, 2008. There was no outstanding balance under this credit facility at September 30, 2008 and we terminated it without penalty in October, 2008 (see footnote 12 Subsequent Events in these financial statements).

Senior Secured Revolving Credit Facility
On July 15, 2008, we entered into a five year amended and restated credit agreement (the Agreement) with Wells Fargo Bank, N.A. as administrative agent and other lenders. The Agreement amends and restates the Company's previous credit agreement dated as of April 28, 2006, as amended. The Agreement is a revolving credit facility for up to $1.5 billion with a borrowing base of $1.0 billion. The outstanding Line of Credit reduces our borrowing capacity available under the Agreement. The borrowing base under the previous agreement was $650 million. Interest on amounts borrowed under this debt is charged at LIBOR plus a margin of 1.125% to 1.875% or the prime rate, 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. The deferred costs of approximately $8.2 million associated with the issuance of this credit facility and $.6 million associated with the issuance of the previous credit facility are being amortized over the 5 year life of the Agreement. $.1 million was charged to the income statement as a loss on debt extinguishment during the third quarter of 2008 related to parties who reduced their commitment or chose not to participate in the Agreement.

The total outstanding debt at September 30, 2008 under the Agreement and the Line of Credit was $910 million and $19 million, respectively, and $8 million in letters of credit have been issued under the facility, leaving $63 million in borrowing capacity available under the Agreement and $100 million available under our $100 million senior unsecured credit facility. The maximum amount available is subject to annual redetermination of the borrowing base in accordance with the lender's customary procedures and practices. Both we and the banks have bilateral right to one additional redetermination each year. We further amended this credit facility in October 2008 (see Footnote 12 Subsequent Events in these financial statements).

Senior Subordinated 8.25% notes due 2016

In 2006, we issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Notes). Interest on the Notes is paid semiannually in May and November of each year. 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.

12

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

Financial Covenants

The senior secured revolving credit facility contains restrictive covenants which, among other things, require us to maintain a debt to EBITDA ratio of not greater than 3.5 to 1.0 and a minimum current ratio, as defined, of 1.0. The $200 million Notes are subordinated to our credit facility indebtedness. Under the Notes, as long as the interest coverage ratio (as defined) is greater than 2.5
times, we may incur additional debt. We were in compliance with all of these covenants as of September 30, 2008.

Interest Rates and Interest Rate Hedges

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 beginning on September 29, 2006. These interest rate swaps have been designated as cash flow hedges.

The weighted average interest rate on total outstanding borrowings at September 30, 2008 was 5.3%.

11. 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.

We have a crude oil sales contract with an independent refiner for substantially all of our California production for deliveries beginning February 1, 2006 and ending January 31, 2010. After the initial term of the contract, we have a one-year renewal at our option. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of 1) the WTI NYMEX crude oil price less a fixed differential approximating $8.10, or 2) heavy oil field postings plus a premium of approximately $1.35. The agreement effectively eliminates our exposure to the risk of a widening WTI to California heavy crude price differential over the four year contract term and allows us to effectively hedge our production based on WTI pricing.

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 $15 to $20 per barrel at WTI prices between $60 and $80 per barrel. Gross oil production averaged approximately 4,150 BOE/D in the quarter ended September 30, 2008.

We have two long-term firm transportation contracts for our Colorado natural gas production that total 35,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. We pay a demand charge for this capacity and our own production did not completely 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 pre-tax net of our gas marketing revenue and our gas marketing expense in the Statements of Income is $2.0 million for the nine month period ended September 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 and in order to access the Ruby pipeline, we also secured firm transportation from the Piceance basin to Opal.

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

12. Subsequent Events

On October 17, 2008, we amended our $1.5 billion credit facility with the Company's syndicate of seventeen banks which increased our borrowing base from $1.0 billion to $1.25 billion with current commitments of $1.08 billion and a new maturity date of July 15, 2012. The amendment includes an accordion feature which allows the Company to increase borrowing commitments to $1.25 billion without further bank approval, and modifies the annual commitment fee and interest rate margins. Interest on amounts borrowed under the facility is charged at LIBOR or the prime rate plus a margin. The LIBOR and prime rate margins range between 1.375% and 2.125% based on the ratio of credit outstanding to the borrowing base. Additionally, an annual commitment fee of .30% to .50% is charged on the unused portion of the credit facility. We also terminated our $100 million senior unsecured credit facility without penalty that was to mature at December 31, 2008.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

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 nine month periods ended September 30, 2008 and 2007 and our financial condition, liquidity and capital resources as of September 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:

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

Notable Third Quarter Items.

- Achieved target production averaging 35,150 BOE/D, up 31% from the third quarter of 2007 and up 21% from the second quarter of 2008
- Closed on our East Texas acquisition on July 15, 2008, adding approximately 335 Bcfe of proved reserves
- Increased Diatomite net production to an average of 2,100 BOE/D, up 24% from the second quarter of 2008
- Increased Piceance net average production to 22.7 MMcf/D in the third quarter of 2008, up 37% from the second quarter of 2008
- Production at Poso Creek averaged 3,300 Bbl/D, up 3% from the second quarter of 2008
- Increased both oil and natural gas production during the quarter with oil production up 9% and natural gas production up 89% from the third quarter of 2007
- Amended our credit facility increasing the borrowing base from $600 million to $1 billion
- David D. Wolf joined the Company as Executive Vice President and Chief Financial Officer

Notable Items and Expectations for the Fourth Quarter of 2008.

- Increased the borrowing base on our senior secured credit facility from $1.0 billion to $1.25 billion with an increase in our commitments to $1.08 billion on October 17, 2008
- Reducing drilling activity from 12 rigs to 4 rigs by year-end 2008 with 1 rig in California, 1 rig in the Piceance basin and 2 rigs in East Texas
- Targeting a production average of 37,000 to 38,000 BOE/D in the fourth quarter
- Planning to takeover operations in East Texas from the seller on November 1, 2008

- Anticipating a 2009 Capital budget of approximately $200 million focusing on development of the diatomite and other high return oil projects in California and high impact recompletions in East Texas
- Expect proved reserves at year-end to range between 235-245 MMBOE, up over 40% from 169 MMBOE at year-end 2007, with organic growth of 27 MMBOE

Overview of the Third Quarter of 2008. We had net income of $53.3 million, or $1.17 per diluted share and net cash from operations was $137.4 million in the third quarter of 2008. We drilled 118 gross wells and capital expenditures, excluding property acquisitions, totaled $134.8 million. We achieved average production of 35,150 BOE/D in the third quarter of 2008, up 21% from an average of 29,000 BOE/D in the second quarter of 2008.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

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

	September 30, 2008 (3Q08)	September 30, 2007 (3Q07)	3Q07 to 3Q08 Change	June 30, 2008 (2Q08)	2Q08 to 3Q08 Change
Sales of oil	$ 145	$ 100	45%	$ 146	(1%)
Sales of gas	63	19	232%	39	62%
Total sales of oil and gas	$ 208	$ 119	75%	$ 185	12%
Sales of electricity	18	12	50%	17	6%
Gain on sale of assets	-	2	-%	-	-%
Other revenues	15	1	1,400%	13	15%
Total revenues and other income	$ 241	$ 134	80%	$ 215	12%
Net income	$ 53	$ 27	96%	$ 49	8%
Earnings per share (diluted)	$ 1.17	$ .60	95%	$ 1.08	8%

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 September 30, 2008 were flat with the three months ended June 30, 2008 resulting from price decreases of 1% and sales volume increases of 1%. While crude oil production was 3% higher during the quarter, our sales were up 1% due to a build up in our inventory which we expect to draw during the fourth quarter of 2008. Gas sales in the three months ended September 30, 2008 were 62% higher than the three months ended June 30, 2008 resulting from production increases of 69%, in part due to the East Texas acquisition, and a price decrease of 6%.

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, the 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:

	September 30, 2008	%	September 30, 2007	%	June 30, 2008	%
Heavy Oil Production (Bbl/D)	17,264	49	15,806	59	16,888	58
Light Oil Production (Bbl/D)	3,898	11	3,675	14	3,723	13
Total Oil Production (Bbl/D)	21,162	60	19,481	73	20,611	71
Natural Gas Production (Mcf/D)	83,928	40	44,346	27	50,339	29
Total (BOE/D)	35,150	100	26,873	100	29,000	100
Oil and gas, per BOE:						
Average sales price before hedging	$ 80.22		$ 49.35		$ 91.89	
Average sales price after hedging	64.98		47.93		69.77	

Oil, per Bbl:			
Average WTI price	$ 118.22	$ 75.15	$ 123.80
Price sensitive royalties	(5.30)	(5.50)	(5.92)
Quality differential and other	(10.80)	(9.56)	(11.52)
Crude oil hedges	(26.12)	(4.37)	(29.37)
Average oil sales price after hedging	$ 76.00	$ 55.72	$ 76.99
Natural gas price:			
Average Henry Hub price per MMBtu	$ 10.24	$ 6.24	$ 10.93
Conversion to Mcf	.52	.31	.55
Natural gas hedges	.15	1.07	(.69)
Location, quality differentials and other	(2.81)	(3.06)	(2.15)
Average gas sales price after hedging per Mcf	$ 8.10	$ 4.56	$ 8.64

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations
Operating data. The following table is for the nine months ended:

	September 30, 2008	%	September 30, 2007	%
Heavy Oil Production (Bbl/D)	16,845	54	16,019	60
Light Oil Production (Bbl/D)	3,710	12	3,655	14
Total Oil Production (Bbl/D)	20,555	66	19,674	74
Natural Gas Production (Mcf/D)	61,201	34	41,109	26
Total (BOE/D)	30,755	100	26,525	100
Oil and gas, per BOE:				
Average sales price before hedging	$ 82.57		$ 45.98	
Average sales price after hedging	66.37		45.82	
Oil, per Bbl:				
Average WTI price	$ 113.52		$ 66.22	
Price sensitive royalties	(3.36)		(4.48)	
Quality differential and other	(12.90)		(9.26)	
Crude oil hedges	(23.83)		(1.61)	
Correction to royalties payable	1.88		-	
Average oil sales price after hedging	$ 75.31		$ 50.87	
Natural gas price:				
Average Henry Hub price per MMBtu	$ 9.74		$ 7.02	
Conversion to Mcf	.49		.36	
Natural gas hedges	(.15)		.67	
Location, quality differentials and other	(2.01)		(2.85)	
Average gas sales price after hedging per Mcf	$ 8.07		$ 5.20	

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

Gas Basis Differential. The basis differential between Henry Hub (HH) and Colorado Interstate Gas (CIG) index increased during the third quarter after decreasing at the start up of the Rockies Express Pipeline (REX) in January. The differential averaged $4.31 in the third quarter. In the second quarter of 2008, the CIG basis differential per MMBtu, based upon first-of-month values, averaged $2.45 below HH and ranged from $1.77 to $3.24 below HH. For the third quarter, the differential averaged $4.31 with the range from $2.19 at the start of the quarter to $6.61 below HH at the end of the quarter. The large September differential was due primarily to maintenance on REX which put a large portion of the pipeline out of service for almost the entire month. Maintenance was completed and REX was back in service September 28, 2008. 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 $1.08 above the CIG index pricing before the cost of transportation.

Gas from the Uinta basin sold for approximately $.30 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 $1.91 below the HH index during the third quarter, before the cost of transportation. The remainder of the DJ Basin gas is sold slightly above the CIG index price.

Gas Marketing. We have two long-term (ten year) firm transportation contracts for our Colorado natural gas production. The first contract is for 10,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. The second 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 pre-tax net of our gas marketing revenue and our gas marketing expense in the Statements of Income is $2.0 million in the nine month period ended September 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 and in order to access the Ruby pipeline, we also secured firm transportation from the Piceance basin to Opal.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

Oil Contracts. California - We have a crude oil sales contract with an independent refiner for substantially all of our California production for deliveries beginning February 1, 2006 and ending January 31, 2010. After the initial term of the contract, we have a one-year renewal at our option. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of 1) the WTI NYMEX crude oil price less a fixed differential approximating $8.10, or 2) heavy oil field postings plus a premium of approximately $1.35. The agreement effectively eliminates our exposure to the risk of a widening WTI to California heavy crude price differential over the four year contract term and allows us to effectively hedge our production based on WTI pricing.

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 4,150 BOE/D in the quarter ended September 30, 2008. The differential under the contract, which includes transportation and gravity adjustments, is linked to WTI and would range from $15 to $20 per barrel at WTI prices between $60 and $80. 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 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.

We generally 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. However, wider natural gas price differentials in the Rockies when compared to California will increase our margin on electricity as described above. In the third quarter of 2008, our margin on electricity increased to $4.6 million. Approximately $2 million of this margin was due to lower Rockies gas prices when compared to Southern California border prices and $2.4 million of this change was due to seasonal capacity payments the Company receives 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. The effective date of the new pricing under the SRAC Decision has not been determined as of yet and a portion of the SRAC Decision has been appealed to the Court of Appeal. We do not believe that the proposed pricing changes will materially affect us in 2008.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

The following table is for the three months ended:

	September 30, 2008	September 30, 2007	June 30, 2008
Electricity			
Revenues (in millions)	$ 18.3	$ 12.3	$ 17.0
Operating costs (in millions)	$ 13.7	$ 9.8	$ 15.5
Electric power produced - MWh/D	2,096	2,257	1,919
Electric power sold - MWh/D	1,908	2,077	1,724
Average sales price/MWh	$ 104.91	$ 71.28	$ 108.21
Fuel gas cost/MMBtu (including transportation)	$ 8.20	$ 4.84	$ 10.01

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

	Amount per BOE			Amount (in thousands)		
	September 30, 2008	September 30, 2007	June 30, 2008	September 30, 2008	September 30, 2007	June 30, 2008
Operating costs – oil and gas production	$ 17.33	$ 13.75	$ 20.91	$ 56,038	$ 33,995	$ 55,185
Production taxes	2.99	1.76	2.83	9,673	4,344	7,481
DD&A – oil and gas production	12.51	9.45	11.02	40,440	23,356	29,073
G&A	4.49	3.78	4.23	14,524	9,333	11,160
Interest expense	2.71	1.75	1.50	8,755	4,326	3,951
Total	$ 40.03	$ 30.49	$ 40.49	$ 129,430	$ 75,354	$ 106,850

Our total operating costs, production taxes, DD&A, G&A and interest expenses for the three months ended September 30, 2008, stated on a unit-of-production basis, increased 32% over the three months ended September 30, 2007 and decreased 1% as compared to the three months ended June 30, 2008. The changes were primarily related to the following items:

- Operating costs: Steam costs are the primary variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of fuel used to generate steam. The following table presents steam information:

	September 30, 2008 (3Q08)	September 30, 2007 (3Q07)	3Q07 to 3Q08 Change	June 30, 2008 (2Q08)	2Q08 to 3Q08 Change
Average volume of steam injected (Bbl/D)	105,574	88,711	19%	97,853	8%
Fuel gas cost/MMBtu (including transportation)	$ 8.20	$ 4.84	69%	$ 10.01	(18%)
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	29,362	23,348	26%	27,382	7%

Operating costs increased by $1 million or 2% between the second and third quarters of 2008. The East Texas Acquisition increased our total operating costs on a nominal basis with the impact of decreasing per barrel costs as these natural gas assets have lower per barrel operating costs. This increase was offset by a $4 million decrease in fuel gas costs due to a decrease in natural gas prices offset by increased fuel gas consumption. Our total cost to purchase fuel for our steam operations decreased by $1.81 per MMBtu or 18% in the three months ended September 30, 2008 compared to the three months ended June 30, 2008 as the SoCal border natural gas price decreased over this time period. We plan to increase our fuel gas consumption by 3,000 MMBtu/D in the fourth quarter of 2008 as we add additional steam generation capacity at Poso Creek and the Diatomite.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

- Production taxes: Our production taxes have increased compared to the third quarter of 2007 as commodity prices and thus the value of our oil and natural gas has increased. The increase from the second quarter of 2008 is primarily due to an increase in the assessed value of our properties in California. Severance taxes paid in Utah, Colorado and Texas 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 fluctuate with oil and gas prices.

- Depreciation, depletion and amortization: DD&A increased per BOE by 32% and 14% in the third quarter of 2008 as compared to the third quarter of 2007 and as compared to the second quarter of 2008, respectively, due to an increase in the contribution of our development properties with higher drilling and leasehold acquisition costs and the integration of our East Texas assets which have higher finding and development costs than our legacy assets.

- General and administrative: Approximately 70% of our G&A is related to compensation. The primary reason for the increase in G&A during the third quarter of 2008 as compared to the third quarter of 2007 was due to due to additional staffing and the costs associated with the 2008 relocation of our corporate office from Bakersfield, California to Denver, Colorado.

- Interest expense: Our total outstanding borrowings were approximately $1.1 billion at September 30, 2008 compared to $440 million and $511 million at September 30, 2007 and June 30, 2008, respectively. Our average borrowings increased since June 30, 2008 primarily due to the East Texas acquisition in the third quarter of 2008. For the three months ended September 30, 2008, $7 million of interest cost has been capitalized and we expect to capitalize approximately $23 million of interest cost during the full year of 2008.

Estimated 2008 and Actual Nine Months Ended September 30, 2008 and 2007 Oil and Gas Operating, G&A and Interest Expenses. Based upon our reduced activity in the fourth quarter of 2008, we estimate our average 2008 production volume will range between 32,000 BOE/D and 33,000 BOE/D.

	Anticipated range Full Year 2008 per BOE	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Operating costs-oil and gas production	$ 17.00 to 19.00	$ 18.14	$ 14.27
Production taxes	2.50 to 3.00	2.74	1.70
DD&A – oil and gas production (1)	11.75 to 12.25	11.46	9.04
G&A	4.00 to 4.50	4.40	4.05
Interest expense	1.50 to 2.00	1.95	1.88
Total	$ 36.75 to 40.75	$ 38.69	$ 30.94

(1) Full year estimate includes both oil and gas and electricity

Our total operating costs, production taxes, DD&A, G&A and interest expenses for the nine months ended September 30, 2008, stated on a unit-of-production basis, increased 25% over the nine months ended September 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:

	Nine months ended September 30, 2008	Nine months ended September 30, 2007	Change
Average volume of steam injected (Bbl/D)	98,050	86,157	14%
Fuel gas cost/MMBtu (including transportation)	$ 8.70	$ 5.78	51%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	26,128	21,698	20%

Our total cost to purchase fuel for our steam operations increased by $2.92 per MMBtu or 51% in the nine months ended September 30, 2008 compared to the nine months ended September 30, 2007 as the SoCal border natural gas price increased over this time period. We consumed an additional 4,430 MMBtus per day in the first nine months of 2008 when compared to the first nine months of 2007 primarily related to increased conventional steam generation consumption.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

- Production taxes: Production taxes per BOE in the nine months ended September 30, 2008 were 61% higher than the comparable period in 2007 as commodity prices and thus the value of our oil and natural gas has increased. Severance taxes paid in Utah, Colorado and Texas 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.

    - Depreciation, depletion and amortization: DD&A per BOE was 27% higher in the nine months ended September 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 and the integration of our East Texas acquisition.

- General and administrative: G&A per BOE increased by 9% in the nine months ended September 30, 2008 compared to the same period in the prior year due to additional staffing and higher overall compensation costs associated with our growth activities and the relocation of our corporate headquarters.

- Interest expense: Our total outstanding borrowings was approximately $1.1 billion at September 30, 2008 compared to approximately $440 million at September 30, 2007. Our average borrowings increased since September 30, 2007 primarily due to the East Texas acquisition in the third quarter of 2008. For the nine months ended September 30, 2008, $16 million of interest cost has been capitalized.

Royalties. The price sensitive royalty that impacts 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.

Dry Hole, Abandonment, impairment and exploration. In the first nine months of 2008, we recorded a total of $9.2 million in dry hole, abandonment, impairment and exploration expense. Charges of $2.7 million, $2.6 million and $1.5 million were recorded during the first, second and third quarters of 2008, respectively, for technical difficulties that were encountered on five 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 36.5% in both the three months ended September 30, 2008 and the three months ended September 30, 2007. 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 9 to the unaudited condensed financial statements.

Development, Exploitation and Exploration Activity. We drilled 118 gross (101 net) wells during the third quarter of 2008.

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

	Three months ended September 30, 2008		Nine months ended September 30, 2008
Asset Team	Gross Wells	Net Wells	Net Wells

			Gross Wells	
S. Midway	11	11	68	68
N. Midway	23	23	92	92
S. Cal	-	-	25	25
Piceance	26	16	65	37
Uinta	16	16	45	45
DJ	33	26	79	65
Texas	9	9	9	9
Totals	118	101	383	341

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

Properties

Asset Team Descriptions

S. Midway – During the three months ended September 30, 2008, production averaged approximately 8,950 Bbl/D compared to approximately 9,350 Bbl/D and 9,100 Bbl/D during the three month periods ended September 30, 2007 and June 30, 2008, respectively. In 2008 we drilled 18 deeper horizontal wells in the reservoir. This series of horizontal wells, coupled with targeted steam placement, has helped offset the natural decline of the mature resource. In addition we drilled two horizontal wells on the Formax property following the renegotiation of the price sensitive royalty. In 2008, we also began developing the Monarch reservoir on our Ethel D property. We drilled 32 wells in the Monarch in the first nine months of the year and production averaged 1,200 Bbl/D using cyclic steam injection. We believe that Ethel D 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 September 30, 2008, production from the area averaged approximately 3,000 Bbl/D compared to approximately 2,200 Bbl/D and 2,600 Bbl/D during the three month periods ended September 30, 2007 and June 30, 2008, respectively. In October 2007, we embarked on a full-scale, continuous development program of the Diatomite and we expect to drill continuously over the next four years. Over 98 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. The additional wells, steam and supporting infrastructure has enabled us to increase production of the Diatomite which averaged 1,700 BOE/D during the second quarter of 2008 to over 2,100 BOE/D during the third quarter of 2008.

S. Cal – During the three months ended September 30, 2008, production averaged approximately 5,350 Bbl/D compared to approximately 4,300 Bbl/D and 5,300 Bbl/D during the three month periods ended September 30, 2007 and June 30, 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 September 2008, all 28 planned producers have been drilled and Poso Creek production is currently averaging 3,300 BOE/D. During the fourth quarter 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 September 30, 2008, production from the Piceance basin averaged 22.7 MMcf/D, an increase of 37% from the prior quarter. Of the Company operated wells, we drilled 26 gross wells (16 net) during the third quarter of 2008. We have drilled over 130 wells since we acquired our original Piceance basin acreage in early 2006. We are currently operating two drilling rigs and continue to realize further efficiencies with repeated drilling times reduced to 9 to 13 days for a mesa well. Throughout the third quarter of 2008, we realized increasing production from the summer completion season with current production now over 30 MMcf/D. Initial production rates from these wells have been in line with our expectations.

Uinta – Average daily production during the three months ended September 30, 2008 from all Uinta basin assets was approximately 6,400 BOE/D, an increase of 6% from the prior quarter. During the three months ended September 30, 2008, we returned to a one rig drilling program at Brundage Canyon following the temporary operation of two drilling rigs during the prior quarter. The development at Brundage Canyon continues to be focused on drilling high potential areas in the core of the field where we drilled 11 wells in the third quarter of 2008. Evaluating the waterflood feasibility at Brundage Canyon has progressed and we anticipate receiving regulatory approval before year-end with first injection in early 2009. During the third quarter of 2008, we further delineated the Ashley Forest by drilling 4 wells under our existing environmental approvals and currently we are drilling the 8th and final well of our 2008 Ashley Forest program. 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 September 30, 2008, we drilled 33 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 September 30, 2008 was 20 MMcf/D. Earlier this year we completed the interpretation of an additional 75 square miles of 3-D seismic that we acquired over the winter. The seismic surveys replenished our low risk repeatable drilling inventory and we are currently permitting many of those drilling locations for our 2009 capital program.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

East Texas – On July 15, 2008, we acquired certain interests in natural gas producing properties on 4,500 net acres in Limestone and Harrison Counties in East Texas. We have assembled our asset team and plan to take over operations from the seller on November 1, 2008. Production should increase from its current level of approximately 30 MMcf/d as our team transitions field, drilling and completion operations. We drilled 9 wells on the property during the quarter and have brought 2 of these wells on production. We plan to drill approximately 8 wells during the fourth quarter and complete the remaining wells drilled during the third quarter of 2008. We have drilled four vertical Haynesville appraisal wells which demonstrate productivity to support a horizontal development of this resource. We expect to drill our first Haynesville horizontal well during the first half of 2009.

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 secured credit agreement (the Credit Agreement) with Wells Fargo Bank, N.A as administrative agent and other lenders. The total outstanding debt at September 30, 2008 under the Agreement and the short-term Line of Credit was $910 million and $19 million, respectively, and $8 million in letters of credit have been issued under the facility leaving $63 million in borrowing capacity available under the Agreement and $100 million available under our $100 million senior unsecured credit facility.

On October 17, 2008, we amended our $1.5 billion Credit Agreement with the Company's syndicate of seventeen banks which increased our borrowing base from $1.0 billion to $1.25 billion with current commitments of $1.08 billion and a new maturity date of July 15, 2012. The amendment includes an accordion feature which allows the Company to increase borrowing commitments to $1.25 billion without further bank approval, and modifies the annual commitment fee and interest rate margins. As of October 27, 2008 we had $144 million in borrowing capacity available. The maximum amount available is subject to a semi-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.

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 the East Texas Acquisition to a total of $370 million. Increases in steel prices and other services will likely result in total capital spending for the full year 2008 of approximately $400 million. While we have reduced our activity during the fourth quarter of 2008, we do not expect to see the results of this reduction until early in the first quarter of 2009 as we complete projects and release rigs after contractual commitments are complete. Excess cash generated from operations is expected to be applied toward acquisitions, debt reduction or other corporate purposes.

Capital expenditures, excluding property acquisitions, totaled $135 million and $306 million during the three and nine months ended September 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. 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.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

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

	September 30, 2008 (3Q08)	September 30, 2007 (3Q07)	3Q07 to 3Q08 Change	June 30, 2008 (2Q08)	2Q08 to 3Q08 Change
Average production (BOE/D)	35,150	26,873	31%	29,000	21%
Average oil and gas sales prices, per BOE after hedging	$ 64.98	$ 47.93	36%	$ 69.77	(7)%
Net cash provided by operating activities (1)	$ 137	$ 93	47%	$ 107	28%
Working capital	$ (148)	$ (91)	(63)%	$ (225)	34%
Sales of oil and gas	$ 208	$ 119	75%	$ 185	12%
Total debt	$ 1,129	$ 440	157%	$ 511	1,21%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 742	$ 63	1,078%	$ 154	382%
Dividends paid	$ 3.4	$ 3.4	-%	$ 3.4	-%

(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.

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

	Total	2008	2009	2010	2011	2012	Thereafter
Total debt and interest	$ 1,524.7	$ 37.7	$ 70.6	$ 70.6	$ 70.6	$ 70.6	$ 1,204.6
Abandonment obligations	40.4	.4	1.7	1.7	1.6	1.6	33.4
Operating lease obligations	17.5	.6	2.3	2.3	2.3	2.3	7.7
Drilling and rig obligations	74.4	12.4	27.6	15.0	19.4	-	-
Firm natural gas transportation contracts	161.9	3.9	19.5	19.5	19.5	19.1	80.4
Total	$ 1,818.9	$ 55.0	$ 121.7	$ 109.1	$ 113.4	$ 93.6	$ 1,326.1

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 September 30, 2008 we have drilled 29 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 September 30, 2008, we had a gross liability for uncertain tax benefits of $11.9 million of which $9.6 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 $15 to $20 per barrel at WTI prices between $60 and $80. Gross oil production averaged approximately 4,150 BOE/D in the quarter ended September 30, 2008.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

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 or Rockies gas price and we sell our produced gas in Colorado and Utah at various index prices.

The following table summarizes our hedge position as of September 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	4th Quarter 2008	21,000	$ 1.46
Full year 2009	10,000	$ 47.50 / $70.00			
Full year 2009	295	$ 80.00 / $91.00	Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
Full year 2009	1,000	$ 100.00 / $163.60	1st Quarter 2009	15,400	$ 1.17
Full year 2009	1,000	$ 100.00 / $150.30	2nd Quarter 2009	15,400	$ 1.12
Full year 2009	1,000	$ 100.00 / $160.00	3rd Quarter 2009	15,400	$ 0.97
Full year 2009	1,000	$ 100.00 / $150.00	4th Quarter 2009	15,400	$ 1.05
Full year 2009	1,000	$ 100.00 / $157.48	Natural Gas Sales (NYMEX HH) Swaps		

Full year 2010	1,000	$	60.00 / $80.00	4th Quarter 2008	16,200	$	8.04
Full year 2010	1,000	$	55.00 / $76.20	Full year 2009	15,400	$	8.50
Full year 2010	1,000	$	55.00 / $77.75				
Full year 2010	1,000	$	55.00 / $77.70	Natural Gas Sales (NYMEX HH) Collars		Floor/Ceiling Prices	
Full year 2010	1,000	$	55.00 / $83.10	4th Quarter 2008	4,800	$	8.00 / $9.50
Full year 2010	1,000	$	60.00 / $75.00				
Full year 2010	1,000	$	65.50 / $78.50				
Full year 2010	280	$	80.00 / $90.00				
Full year 2010	1,000	$	100.00 / $161.10				
Full year 2010	1,000	$	100.00 / $150.30				
Full year 2010	1,000	$	100.00 / $160.00				
Full year 2010	1,000	$	100.00 / $150.00				
Full year 2010	1,000	$	100.00 / $158.50				
Full year 2011	270	$	80.00 / $90.00				
Crude Oil Sales (NYMEX WTI) Swaps							
Full year 2008	335	$	92.00				
Full year 2009	240	$	71.50				

26

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 $100.00 per barrel while still participating in any oil price increase up to the ceiling prices which range from $70.00 to $163.60 per barrel on the volumes indicated above, and if 2) gas prices decline below our floor price of $8.00 per MMBtu while still participating in any gas price increase up to the ceiling price of $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 gains of approximately $.6 million and unrealized net losses of approximately $.2 million in the Statements of Income under the caption Commodity derivatives for the three months ended September 30, 2008 and for the nine months ended September 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 September 30, 2008 (WTI $103.73; HH $8.20) 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:

	September 30, 2008 NYMEX Futures	Impact of percent change in futures prices on pretax future cash (payments) and receipts			
		-40%	-20%	+ 20%	+40%
Average WTI Futures Price (2008 – 2011)	$ 103.73	$ 62.24	$ 82.98	$ 124.48	$ 145.22
Average HH Futures Price (2008 – 2009)	8.20	4.92	6.56	9.85	11.49

Crude Oil gain/(loss) (in millions)	$ (243.6)	$ 151.7	$ (9.7)	$ (416.5)	$ (589.4)
Natural Gas gain/(loss) (in millions)	4.5	29.2	16.9	(7.3)	(19.5)
Total	$ (239.1)	$ 180.9	$ 7.2	$ (423.8)	$ (608.9)
Net pretax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2008 (WTI $100.47; HH $7.71)	$ (27.1)	$ 12.2	$ (2.7)	$ (51.0)	$ (75.2)
2009 (WTI $102.10; HH $8.33)	(120.6)	92.8	(0.2)	(208.4)	(296.3)
2010 (WTI $104.60)	(89.9)	74.3	10.1	(160.8)	(231.7)
2011 (WTI $105.31)	(1.5)	1.6	-	(3.6)	(5.7)
Total	$ (239.1)	$ 180.9	$ 7.2	$ (423.8)	$ (608.9)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued, in a public offering, $200 million of 8.25% senior subordinated notes due 2016. At September 30, 2008, total long-term debt outstanding including our short-term Line of Credit, was $1.1 billion. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 1.25% to 1.875%, 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 July 15, 2013. Based on September 30, 2008 credit facility borrowings, a 1% change in interest rates would have an annual $−−5.2 million after tax impact on our financial statements.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

Item 4. Controls and Procedures

As of September 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 September 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 September 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. 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 dated February 27, 2008, 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

It is possible that the borrowing base of our senior secured revolving credit facility may decrease. Our borrowing base is subject to a semi-annual redetermination each April and October and our Lenders and the Company have the right to one incremental redetermination each year. Our borrowing base of $1.25 billion that was confirmed on October 17, 2008 was determined based on lender criteria which vary in commodity price by individual lender. Should lender price assumptions decrease significantly, our borrowing base may decrease to an amount less than our current outstanding in which case we would be required to fund such deficiency. Subsequent to a redetermination any amount outstanding in excess of our borrowing base must be cured in two equal installments 90 and 180 days after our lenders give us notice of such deficiency.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Item 5. Other Information

None.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

Item 6. Exhibits

Exhibit No.	Description of Exhibit
10.1*	Amended and Restated Credit Agreement, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., and other financial institutions, dated July 15, 2008 (previously filed on July 25, 2008, as Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q File No 1-9735)
10.2	Credit Agreement by and among Berry Petroleum Company, Société Générale, SG Americas Securities, LLC, BNP Paribas Securities Corp., BNP Paribas, and other financial institutions dated July 31, 2008
10.3*	First Amendment to Amended and Restated Credit Agreement, by and between Berry Petroleum Company, Wells Fargo Bank, N.A. and other financial institutions, dated as of October 17, 2008 (previously filed on October 17, 2008, as Exhibit 10.1 to Registrant's Current Report on Form 8-K 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

* Incorporated herein by reference

SIGNATURE

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

BERRY PETROLEUM COMPANY

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

Date: October 29, 2008