BERRY PETROLEUM CO
Form 10-K/A
August 12, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

(Amendment No. #1)

x **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2009

Commission file number 1-9735

BERRY PETROLEUM COMPANY

(Exact name of registrant as specified in its charter)

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

1999 Broadway

Suite 3700

Denver, Colorado 80202

(Address of principal executive offices, including zip code)

Registrant s telephone number, including area code:

(303) 999- 4400

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Stock, $0.01 par value (including associated stock purchase rights)	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES x NO o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES o NO x

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES o NO o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer, or a smaller reporting company. See definition of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

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

As of June 30, 2009, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $684,959,425. As of February 1, 2010, the registrant had 50,952,786 shares of Class A Common Stock outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on February 1, 2010 all of which are held by an affiliate of the registrant.

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EXPLANATORY NOTE

Berry Petroleum Company (the Registrant) is filing this Amendment No. 1 (this Amendment) to its Annual Report on Form 10-K for the fiscal year ended December 31, 2009 (the Form 10-K). The sole purpose of this Amendment No. 1 is to amend Item 8 of the Form 10-K to correct the presentation error in the Statement of Comprehensive Income (Loss) for the year ended December 31, 2009 and the related disclosures in Note 3 to the audited financial statements. Comprehensive income (loss) in the Form 10-K reflected a net gain from the change in fair value of derivatives of $174.1 million, which should have been reflected as a net loss. The unrealized gains (losses) on derivatives, net of income tax, has been revised from a gain of $205.3 million to a loss of $129.3 million. The reclassification of realized (gains) losses on derivatives included in net income, net of taxes, has been revised from a gain of $31.2 million to a gain of $44.8 million. Accordingly, this Amendment reflects comprehensive loss of approximately $120.0 million, rather than comprehensive income of $228.1 million reflected in the Form 10-K. These corrections were also included in the Company s Form 10-Q for the period ended June 30, 2010 filed August 9, 2010. Except to correct Item 8 of the Form 10-K as described above, no other items or disclosures in the Form 10-K have been amended, and all other information included in the Form 10-K remains unchanged. This Amendment does not reflect events occurring after the filing of the Form 10-K or modify, amend or update any items or disclosures therein in any way other than as required to reflect the changes identified above.

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Item 8. Financial Statements and Supplementary Data

Financial statement schedules have been omitted since they are either not required, are not applicable, or the required information is shown in the financial statements and related notes.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Berry Petroleum Company:

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the financial statements, the Company changed the manner in which it accounts for recurring fair value measurements of financial instruments in 2008. As discussed in Note 9 to the financial statements, the Company changed the manner in which it accounts for earnings per share in 2009.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado

February 25, 2010, except for the effects of the matter discussed in Note 17, as to which the date is August 11, 2010

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BERRY PETROLEUM COMPANY

Balance Sheets

December 31, 2009 and 2008

(In Thousands, Except Share Information)

		2009		2008
ASSETS				
Current assets:				
Cash and cash equivalents	$	5,311	$	240
Short-term investments		66		66
Accounts receivable, net of allowance for doubtful accounts of $38,508 and $38,511, respectively		74,337		65,873
Deferred income taxes		5,623		
Fair value of derivatives		11,527		111,886
Prepaid expenses and other		6,612		11,015
Total current assets		103,476		189,080
Oil and gas properties (successful efforts basis), buildings and equipment, net		2,106,385		2,254,425
Fair value of derivatives		735		79,696
Other assets		29,539		19,182
	$	2,240,135	$	2,542,383
LIABILITIES AND SHAREHOLDERS EQUITY				
Current liabilities:				
Accounts payable	$	63,096	$	119,221
Revenue and royalties payable		25,878		34,416
Accrued liabilities		29,320		34,566
Line of credit				25,300
Income taxes payable				187
Fair value of derivatives		33,843		1,445
Deferred income taxes				45,490
Total current liabilities		152,137		260,625
Long-term liabilities:				
Deferred income taxes		237,161		270,323
Senior secured revolving credit facility		372,000		931,800
8¼% Senior subordinated notes due 2016		200,000		200,000
10¼% Senior notes due 2014, net of unamortized discount of $13,456 and $0, respectively		436,544		
Asset retirement obligation		43,487		41,967
Other long-term liabilities		19,711		5,921
Fair value of derivatives		75,836		4,203
		1,384,739		1,454,214
Commitments and contingencies (Note 13)				
Shareholders equity:				
Preferred stock, $0.01 par value, 2,000,000 shares authorized; no shares outstanding				
Capital stock, $0.01 par value:				
Class A Common Stock, 100,000,000 shares authorized; 42,952,499 shares issued and outstanding (42,782,365 in 2008)		430		427
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899)		18		18
Capital in excess of par value		89,068		79,653
Accumulated other comprehensive (loss) income		(60,372)		113,697
Retained earnings		674,115		633,749

Total shareholders equity		703,259		827,544
	$	2,240,135	$	2,542,383

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

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BERRY PETROLEUM COMPANY

Statements of Income

Years ended December 31, 2009, 2008 and 2007

(In Thousands, Except Per Share Data)

	2009	2008	2007
REVENUES			
Sales of oil and gas	$ 506,691	$ 649,248	$ 433,208
Sales of electricity	36,065	63,525	55,619
Gas marketing	22,806	35,750	
Gain (loss) on derivatives	6,514	(213)	13
Gain (loss) on sale of assets	826	(1,297)	54,173
Interest and other income, net	1,810	3,504	4,414
	574,712	750,517	547,427
EXPENSES			
Operating costs - oil and gas production	156,612	188,758	130,940
Operating costs - electricity generation	31,400	54,891	45,980
Production taxes	18,144	26,876	14,651
Depreciation, depletion & amortization - oil and gas production	139,919	125,595	82,861
Depreciation, depletion & amortization electricity generation	3,681	2,812	3,568
Gas marketing	21,231	32,072	
General and administrative	49,237	54,279	39,663
Interest	49,923	23,942	15,069
Extinguishment of debt	10,823		
Dry hole, abandonment, impairment and exploration	5,425	10,543	8,351
Bad debt expense		38,665	
	486,395	558,433	341,083
Income before income taxes	88,317	192,084	206,344
Provision for income taxes	28,349	70,308	79,060
Income from continuing operations	59,968	121,776	127,284
(Loss) income from discontinued operations, net of tax	(5,938)	11,753	2,644
Net income	$ 54,030	$ 133,529	$ 129,928
Basic net income from continuing operations per share	1.31	2.70	2.85
Basic net (loss) income from discontinued operations per share	(0.13)	0.26	0.06
Basic net income per share	$ 1.18	$ 2.96	$ 2.91
Diluted net income from continuing operations per share	1.30	2.66	2.81
Diluted net (loss) income from discontinued operations per share	(0.13)	0.26	0.06
Diluted net income per share	$ 1.17	$ 2.92	$ 2.87

Statements of Comprehensive Income (Loss)

Years Ended December 31, 2009, 2008 and 2007

(In Thousands)

Net income	$	54,030	$	133,529	$	129,928
Unrealized gains (losses) on derivatives, net of income taxes of ($79,240), $96,546, and ($66,627), respectively		(129,287)		157,522		(99,941)
Reclassification of realized (gains) losses on derivatives included in net income, net of income taxes of ($27,447), $47,119 and ($524), respectively		(44,782)		76,879		(786)
Comprehensive income (loss)	$	(120,039)	$	367,930	$	29,201

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

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BERRY PETROLEUM COMPANY

Statements of Shareholders Equity

Years Ended December 31, 2009, 2008 and 2007

(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shareholders Equity
Balances at January 1, 2007	$ 421	$ 18	$ 50,166	$ 397,072	$ (19,977)	$ 427,700
Stock-based compensation (484,451 shares)	4		12,930			12,934
Tax impact of stock option exercises			3,049			3,049
Deferred director fees - stock compensation			445			445
Cash dividends declared - $0.30 per share, including RSU dividend equivalents				(13,292)		(13,292)
Adoption of authoritative accounting guidance regarding uncertainty in income taxes				(63)		(63)
Change in fair value of derivatives					(100,727)	(100,727)
Net income				129,928		129,928
Balances at December 31, 2007	425	18	66,590	513,645	(120,704)	459,974
Stock-based compensation (199,363 shares)	2		11,684			11,686
Tax impact of stock option exercise			938			938
Deferred director fees stock compensation			441			441
Cash dividends declared - $0.30 per share, including RSU dividend equivalents				(13,425)		(13,425)
Change in fair value of derivatives					234,401	234,401
Net income				133,529		133,529
Balances at December 31, 2008	427	18	79,653	633,749	113,697	827,544
Stock-based compensation (170,134 shares)	3		6,750			6,753
Tax impact of stock option exercises			(98)			(98)
Deferred director fees - stock compensation			2,763			2,763
Cash dividends declared - $0.30 per share, including RSU dividend equivalents				(13,664)		(13,664)
Change in fair value of derivatives					(174,069)	(174,069)
Net income				54,030		54,030
Balances at December 31, 2009	$ 430	$ 18	$ 89,068	$ 674,115	$ (60,372)	$ 703,259

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

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BERRY PETROLEUM COMPANY

Statements of Cash Flows

Years Ended December 31, 2009, 2008 and 2007

(In Thousands)

	2009	2008	2007
Cash flows from operating activities:			
Net income	$ 54,030	$ 133,529	$ 129,928
Depreciation, depletion and amortization	145,788	141,049	97,259
Extinguishment of debt	10,823		
Amortization of debt issuance costs and net discount	6,827	1,774	774
Dry hole and impairment	14,859	9,932	12,951
Commodity derivatives	247	(108)	574
Stock-based compensation expense	8,626	9,313	8,200
Deferred income taxes	19,998	67,982	62,465
Loss (gain) on sale of asset	79	1,297	(54,173)
Other, net	(4,016)	(2,530)	2,787
Cash paid for abandonment	(1,030)	(4,607)	(1,188)
Allowance for bad debt		38,511	
Change in book overdraft	(16,018)	23,984	(9,400)
(Increase) decrease in current assets other than cash, cash equivalents and short-term investments	(10,055)	10,281	(47,876)
(Decrease) increase in current liabilities other than line of credit	(17,582)	(20,838)	36,578
Net cash provided by operating activities	212,576	409,569	238,879
Cash flows from investing activities:			
Exploration and development of oil and gas properties	(134,946)	(397,601)	(285,267)
Property acquisitions	(13,497)	(667,996)	(56,247)
Capitalized interest	(30,107)	(23,209)	(18,104)
Proceeds from sale of assets	139,796	2,037	72,405
Net cash used in investing activities	(38,754)	(1,086,769)	(287,213)
Cash flows from financing activities:			
Proceeds from issuances on line of credit	387,700	404,000	395,150
Payments on line of credit	(413,000)	(393,000)	(396,850)
Proceeds from issuance of long-term debt	1,090,262	1,708,700	229,300
Payments on long-term debt	(1,215,100)	(1,021,900)	(174,300)
Debt issuance costs	(23,955)	(11,002)	(1)
Financing obligation	18,214		
Dividends paid	(13,664)	(13,425)	(13,292)
Proceeds from stock option exercises	890	2,813	5,178
Excess tax (expense) benefit	(98)	938	3,049
Net cash (used in) provided by financing activities	(168,751)	677,124	48,234
Net increase (decrease) in cash and cash equivalents	5,071	(76)	(100)
Cash and cash equivalents at beginning of year	240	316	416
Cash and cash equivalents at end of year	$ 5,311	$ 240	$ 316
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest	$ 36,854	$ 15,708	$ 15,841
Income taxes paid	$ 8,769	$ 13,290	$ 6,715
Supplemental non-cash activity:			
(Decrease) increase in fair value of derivatives:			
	$ (81,439)	$ 123,628	$ (54,844)

Current (net of income taxes of ($49,914), $75,772, and ($36,562), respectively)						
Non-current (net of income taxes of ($56,773), $67,893, and ($30,589), respectively)		(92,630)		110,773		(45,883)
Net (decrease) increase to accumulated other comprehensive (loss) income	$	(174,069)	$	234,401	$	(100,727)

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

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BERRY PETROLEUM COMPANY

Notes to the Financial Statements

1. Summary of Significant Accounting Policies

Description of the business

Berry Petroleum Company (the Company) is an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. The Company has invested in cogeneration facilities which provide steam required for the extraction of heavy oil and which generates electricity for sale.

Basis of presentation

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications and error corrections

Included in the fourth quarter of 2009 are adjustments to correct the prior accounting for the Company s royalties in the amount of $3.3 million, which resulted in decreasing its sales of oil and gas and increasing its royalties payable. The year- to-date impact of the adjustment was $1.9 million. Management concluded the impact was immaterial to the current and prior periods.

In March 2008, the Company determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. The Company 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 sales of oil and gas by $10.5 million and reducing royalties payable.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with a remaining maturity of three months or less to be cash equivalents. The Company s cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at December 31, 2009 and 2008 is $15.7 million and $31.8 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Accounts receivable

Trade accounts receivable consist mainly of receivables from oil and gas purchases and joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, oil and gas receivables are collected within two months.

Allowance for doubtful accounts

The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability. As of both December 31, 2009 and 2008, the Company has an allowance for doubtful accounts of $38.5 million. The 2008 amount represents the Company s November and December 2008 sales to BWOC. The Company had a long-term contract to sell all of its heavy crude oil in California for approximately $8.10 below WTI with BWOC. On December 22, 2008, Flying J, Inc. and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC each filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company s production. On March 17, 2009, the Company entered into a stipulation with BWOC, terminating the contract effective as of March 16, 2009. The Company recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of that $38.5 million due from BWOC, $11.8 million represents 20 days of December 2008 crude oil sales and an administrative claim under the bankruptcy proceedings and $26.7 million represents November and the balance of December 2008 crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to the Company for damages under this contract. While the Company also has guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, the information received from the bankruptcy proceedings to date has not provided the Company with adequate data from which to make a conclusion that any amounts will be collected. The Company has entered into various agreements with other companies to sell its California oil production.

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Discontinued operations

In 2009, the Company sold its DJ Basin assets, the results of operations of which, are reported as discontinued operations in the Statement of Income.

Income taxes and uncertain tax positions

Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are accounted for using the asset and liability method, which results in the recognition of deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. A valuation allowance is recognized if it is determined that deferred tax assets may not be fully utilized in future periods. Income tax positions must meet a more-likely-than-not recognition threshold to be recognized, and any potential accrued interest and penalties related to the unrecognized tax benefits are recognized within income tax expense. Uncertain tax positions are recognized in the Balance Sheet as a current or noncurrent liability, based upon the expected timing of the payment to a taxing authority.

Derivatives

The Company periodically enters into commodity derivative contracts to manage its exposure to oil and natural gas price volatility. The Company also enters into derivative contracts to mitigate the risk of interest rate fluctuations. The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, has no effect on the statement of income because changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative s fair value. Any ineffective portion of the derivative instrument s change in fair value is recognized immediately in earnings. The estimated fair value of derivative instruments requires substantial judgment. These values are based upon, among other things, whether or not the forecasted hedged transaction will occur, option pricing models, futures prices, volatility, time to maturity and credit risk. The values the Company reports in its financial statements changes as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond its control.

Prior to January 1, 2010, the Company designated most of its commodity and interest rate derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to Accumulated other comprehensive loss (AOCL). Effective January 1, 2010, the Company has elected to de-designate all of its commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively.

As a result, subsequent to December 31, 2009, the Company will recognize all gains and losses from prospective changes in commodity and interest rate derivative fair values immediately in earnings rather than deferring any such amounts in AOCL. At December 31, 2009, AOCL consisted of $97 million ($60 million after tax) of unrealized losses, representing the mark-to-market value of the Company s cash flow hedges as of the balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such mark-to-market values at December 31, 2009 are frozen in AOCL as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions affect earnings. The Company expects to reclassify into earnings from AOCL the frozen value related to de-designated commodity hedges during the next three years.

Oil and gas properties, buildings and equipment

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion and the related capitalized costs are reviewed quarterly. Exploratory wells that discover potentially economic reserves in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized if the well found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The costs of development wells are capitalized whether productive or nonproductive.

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Depletion of oil and gas producing properties is computed using the units-of-production method. Depreciation of lease and well equipment, including cogeneration facilities and other steam generation equipment and facilities, is computed using the units-of-production method or on a straight-line basis over estimated useful lives ranging from 10 to 20 years. Buildings and equipment are recorded at cost. Depreciation is provided on a straight-line basis over estimated useful lives ranging from 5 to 30 years for buildings and improvements and 3 to 10 years for machinery and equipment. Estimated residual salvage value is considered when determining depreciation, depletion and amortization (DD&A) rates. Changes in reserves are applied on a prospective basis.

Interest incurred on funds borrowed to finance exploration and certain acquisition and development activities is capitalized. To qualify for interest capitalization, the costs incurred must relate to the acquisition of unproved reserves, drilling of wells to prove up the reserves and the installation of the necessary pipelines and facilities to make the property ready for production. Such capitalized interest is included in oil and gas properties, buildings and equipment. Capitalized interest is added into the depreciable base of the assets and is expensed on a units-of-production basis over the life of the respective project.

In accordance with authoritative guidance, the Company groups assets at the field level and periodically reviews the carrying value of its property and equipment to test whether current events or circumstances indicate such carrying value may not be recoverable. If the tests indicate that the carrying value of the asset is greater than the estimated future undiscounted cash flows to be generated by such asset, then an impairment adjustment needs to be recognized. Such adjustment consists of the amount by which the carrying value of such asset exceeds its fair value. The Company generally measures fair value by considering sale prices for similar assets or by discounting estimated future cash flows from such asset using an appropriate discount rate. Considerable management judgment is necessary to estimate the fair value of assets, and accordingly, actual results could vary significantly from such estimates. When assets are sold, the applicable costs and accumulated depreciation and depletion are removed from the accounts and any gain or loss is included in income. Expenditures for maintenance and repairs are expensed as incurred.

Asset retirement obligations

Asset retirement obligations (ARO) relate to future costs associated with plugging and abandonment of oil and gas wells, removal of equipments and facilities from leased acreage and returning such land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred (typically when the asset is installed at the production location), and the cost of such liability increases the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period through charges to depreciation, depletion and amortization expense, and the capitalized cost is depleted on a units-of-production basis over the proved developed reserves of the related asset. Revisions to estimated retirement obligations result in adjustments to the related capitalized asset and corresponding liability.

Accrued liabilities

Accrued liabilities consist primarily of accrued property taxes, accrued interest and accrued payroll costs. Accrued property taxes were $8.3 million and $13.5 million as of December 31, 2009 and 2008, respectively. Accrued interest was $6.9 million and $8.4 million as of December 31, 2009 and 2008, respectively. Accrued payroll costs were $8.2 million and $8.4 million as of December 31, 2009 and 2008, respectively.

Revenue recognition

Revenues associated with sales of crude oil, natural gas, electricity and natural gas marketing are recognized when delivery has occurred and title has transferred, and if the collectability of the revenue is probable. The electricity and natural gas the Company produces and uses in its operations are not included in revenues. Revenues from crude oil and natural gas production from properties in which the Company has an interest with other producers are recognized on the basis of its net working interest (entitlement method). Revenues are derived from gas marketing sales which represent excess capacity on the Rockies Express pipeline which the Company uses to market natural gas for its working interest partners.

Electricity cost allocation

The Company owns three cogeneration facilities. Its investment in cogeneration facilities has been for the express purpose of lowering steam costs in its heavy oil operations and securing operating control of the respective steam generation. Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine that would otherwise be wasted, to produce steam. Such cogeneration operations produce electricity and steam. The Company allocates steam costs to its oil and gas operating costs based on the conversion efficiency of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. Electricity used in oil and gas operations is allocated at cost. A portion of the capital costs of the cogeneration facilities is allocated to DD&A-oil and gas production.

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Electricity consumption included in oil and gas operating costs for the years ended December 31, 2009, 2008 and 2007 was $2.8 million, $5.8 million and $5.0 million, respectively.

Transportation costs

Transportation costs, consisting primarily of natural gas transportation costs, are included in either Operating costs - oil and gas production or Operating costs - electricity generation, as applicable. Natural gas transportation costs included in Operating costs - oil and gas production were $15.2 million, $9.5 million and $1.2 million for 2009, 2008 and 2007, respectively. Natural gas transportation costs included in Operating costs - electricity generation were $2.8 million, $7.2 million and $6.7 million for 2009, 2008 and 2007, respectively. Additionally, the transportation costs in Uinta were $0.2 million, $0.2 million and $1.4 million in 2009, 2008 and 2007, respectively.

Stock-based compensation

The Company recognizes the grant date fair value of stock options and other stock based compensation issued in the statement of income. Expense is recognized on a straight-line basis over the employee s requisite service period (generally the vesting period of the award).

Earnings (loss) per share

Basic earnings (loss) per share is computed by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. Under the treasury stock method, diluted earnings (loss) per share is computed by dividing net earnings (loss) adjusted for the effects of potential common shares.

Related party transactions

In December 2007, the Company accepted a tender issued by Bakersfield Fuel & Oil Company (BFO) to purchase all of its shares in BFO for $2.9 million. These proceeds are reflected in the Proceeds from sale of assets line on the Statements of Cash Flows and in the Gain on sale of assets line on the Statements of Income. Mr. Thomas Jamieson is a Director of Berry Petroleum Company and a director and the controlling stockholder of BFO. The tender was made to all shareholders of BFO other than Mr. Jamieson and his affiliates. The Corporate Governance and Nominating Committee, with input from the Audit Committee, approved this transaction.

Equity method investments

The Company owns interests in two entities which serve to gather and transport natural gas in the Company s Lake Canyon and Brundage Canyon fields. The Company owns less than 50% interest in both entities and these interests are accounted for using the equity method. The Company s net investment in these entities is included under the caption Other assets on its Balance Sheet.

Impact of recently issued accounting standard updates

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-06 *Improving Disclosures about Fair Value Measurements.* The ASU amends previously issued authoritative guidance and requires new disclosures and clarifies existing disclosures and is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the rollforward activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. As this requires only additional disclosures, the guidance will have no impact on the Company s financial position or results of operations.

2. Fair Value Measurement

In September 2006, authoritative guidance was issued that defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The Company adopted this guidance as of January 1, 2008 for all financial and nonfinancial assets and liabilities recognized or disclosed at fair value on a recurring basis. The Company has also adopted the authoritative guidance as it relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis as of January 1, 2009 pursuant to the authoritative guidance issued by the FASB in February 2008. The adoption of the authoritative guidance did not have a material impact on the financial statements for the years ended December 31, 2009 or 2008.

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The authoritative guidance establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

A financial instrument s categorization within the fair value hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Oil swaps, natural gas swaps and interest rate swaps are valued using internal models which are based on active market data and are classified within Level 2 of the valuation hierarchy. 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. The Company determines the value of option contracts utilizing industry-standard option pricing models based on inputs that are either readily available in public markets, can be derived from information available in publicly quoted markets, or are quoted by financial institutions that trade these contracts. In situations where the Company obtains inputs via quotes from financial institutions, it verifies the reasonableness of these quotes via similar quotes from another financial institution as of each date for which financial statements are prepared. The Company also considers counterparty credit risk and its own credit risk in its determination of all estimated fair values. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative contracts it holds. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps.

The following tables set forth by level within the fair value hierarchy the Company s assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2009 and 2008.

Assets and liabilities measured at fair value on a recurring basis

December 31, 2009 (in millions)		**Total carrying value on the Balance Sheet**		**Level 2**		**Level 3**
Commodity derivative liability	$	(88.5)	$	(62.5)	$	(26.0)
Interest rate swaps liability		(8.9)		(8.9)		
Total liabilities at fair value	$	(97.4)	$	(71.4)	$	(26.0)

December 31, 2008 (in millions)	**Total carrying value on the Balance Sheet**	**Level 2**	**Level 3**
Commodity derivative asset	198.4	25.9	172.5
Interest rate swaps liability	(12.5)	(12.5)	
Total assets at fair value	185.9	13.4	172.5

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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)	**Twelve months ended December 31, 2009**	**Twelve months ended December 31, 2008**
Fair value asset (liability), beginning of period	$ 172.5	$ (194.3)
Total realized and unrealized (losses) gains included in Gain (loss) on derivatives	(1.0)	0.4
Purchases, sales and settlements, net	(200.9)	366.4
Transfers in and/or out of Level 3	3.4	
Fair value (liability) asset, end of period	(26.0)	172.5
Total unrealized (losses) gains included in income related to financial assets and liabilities still on the balance sheet at December 31, 2009 and 2008	$ (0.1)	$

The $3.4 million of transfers out of Level 3 for the year ended December 31, 2009 represent crude oil collars that were converted to crude oil swaps during the first quarter of 2009.

For further discussion related to the Company s derivatives see Note 3 to the financial statements.

Fair Market Value of Financial Instruments

The Company used various assumptions and methods in estimating the fair values of its financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short-term maturity of these instruments. The carrying amount of the Company s credit facilities approximated fair value, because the interest rates on the credit facilities are variable. The fair values of the 8.25 % senior subordinated notes due 2016 and the 10.25 % senior notes due 2014 were estimated based on quoted market prices. The fair values of the Company s derivative instruments and other investments are discussed above.

(in millions)	**Carrying Amount**	**Estimated Fair Value**
	As of December 31, 2009	
Line of credit	$	$
Senior secured revolving credit facility	372	372

8.25 % Senior subordinated notes due 2016		200		196
10.25% Senior notes due 2014		437		487
	$	1,009	$	1,055

(in millions)		Carrying Amount As of December 31, 2008		Estimated Fair Value
Line of credit	$	25	$	25
Senior secured revolving credit facility		932		932
8.25 % Senior subordinated notes due 2016		200		116
	$	1,157	$	1,073

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Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

In December 2009, subsequent to the approval of the Company s capital budget, the Company recorded a $4.2 million impairment charge related to the write down of a drilling rig to its fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management s expectations for the future and include estimates of future oil and gas production, commodity prices based on published forward commodity price curves as of the date of the estimate, operational costs, and a risk-adjusted discount rate. The fair value measurement was based on Level 3 inputs. The fair value of the drilling rig on December 31, 2009 was $3.3 million.

3. Hedging

To minimize the effect of a downturn in oil and gas prices and protect the Company s profitability and the economics of its development plans, the Company enters 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 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. The Company benefits from lower natural gas pricing as it is a consumer of natural gas in its California operations. In the Rocky Mountains and E. Texas the Company benefits from higher natural gas pricing. The Company has 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 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 its Board of Directors. Currently, the hedges are in the form of swaps and collars. However, the Company may use a variety of hedge instruments in the future to hedge WTI or the index gas price. The Company also utilizes interest rate derivatives to protect against changes in interest rates on its floating rate debt.

At December 31, 2009, the net fair value derivative liability was $97.4 million as compared to a net fair value asset of $185.9 million at December 31, 2008 which reflects changes in commodity prices and interest rates. Based on NYMEX strip pricing as of December 31, 2009, the Company expects to make hedge payments under the existing derivatives of $21.7 million during the next twelve months.

At December 31, 2009, AOCL consisted of $(60.4) million, net of tax, of unrealized losses from crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at December 31, 2009, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such mark-to-market values at December 31, 2009 are frozen in AOCL as of the de-designation date and will be reclassified into earnings in the same period that the forecasted transactions impact earnings.

The related cash flow impact of all of the Company s hedges is reflected in cash flows from operating activities.

The Company presents its derivative assets and liabilities on its Balance Sheets on a net basis. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with a counterparty to a derivative contract. The Company uses these agreements to manage and reduce its potential counterparty credit risk.

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The following table disaggregates the Company s net derivative assets and liabilities into gross components on a contract-by-contract basis before giving effect to master netting arrangements. Finally, the Company identifies the line items on its Balance Sheets in which these fair value amounts are included. The gross asset and liability values in the table below are segregated between those derivatives designated in qualifying hedge accounting relationships and those not designated in hedge accounting relationships. The Company uses the end of period accounting designation to determine the classification for each derivative position.

	As of December 31, 2009			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Oil	Current assets	$ 14.2	Current liability	$ 30.8
Commodity Natural Gas	Current assets	1.3		
Commodity Oil			Long term liabilities	74.1
Commodity Natural Gas	Long term assets	0.4		
Commodity Natural Gas	Current liability	0.2		
Commodity Natural Gas	Long term liabilities	1.2		
Interest rate contracts	Long term assets	0.3	Current assets	3.5
Interest rate contracts			Current liabilities	2.7
Interest rate contracts			Long term liabilities	3.0
Total derivatives designated as hedging instruments under authoritative guidance		17.6		114.1
Commodity Natural Gas			Current assets	0.4
Commodity Natural Gas			Current liabilities	0.5
Total derivatives not designated as hedging instruments under authoritative guidance				0.9
Total Derivatives		$ 17.6		$ 115.0

The tables below summarize the Statement of Income impacts of the Company s derivative instruments before tax for the twelve months ending December 31, 2009 (in millions):

Derivatives cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCL on Derivative (Effective portion)	Location of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Location of Gain (loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain (Loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
Commodity - Oil	$ (219.3)	Sales of oil and gas	$ 53.9	Sales of oil and gas	$
Commodity - Natural Gas	12.9	Sales of oil and gas	25.4	Gain (loss) on derivatives	(0.6)
Interest rate	(2.7)	Interest expense	(7.0)	Gain (loss) on derivatives	
Total	$ (209.1)		$ 72.3		$ (0.6)

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Amount of Gain or (Loss) Recognized in Income on Derivatives not designated as Hedging Instruments under authoritative guidance as of twelve months ending December 31, 2009:

Derivatives not designated as Hedging Instruments under authoritative guidance	**Location of Gain (Loss) Recognized in Income on Derivative**		**Amount of Gain (Loss) Recognized in Income on Derivatives not designated as Hedging Instruments under authoritative guidance**
Commodity Oil	Gain (loss) on derivatives	$	(6.7)
Commodity - Natural Gas	Gain (loss) on derivatives		(0.5)
Commodity - Natural Gas	(Loss) income from discontinued operations, net of taxes		(0.5)
Total Derivatives		$	(7.7)

During the first quarter of 2009, the Company converted oil collars for 6,000 Bbl/D for the full year 2010 into swaps for the same volumes with swap prices ranging from $61.00 to $64.80.

The Company generally utilizes NYMEX WTI based derivatives to hedge cash flows from its California oil sales. The Company s oil sales contracts with multiple refiners are primarily based on the field posting prices. There is a high correlation between WTI and the field posting prices which allowed us to utilize hedge accounting. As there is a ready market for the Company s crude oil in California, the Company does not believe the loss of any particular contract impacts the probability that its hedged forecasted transactions will occur. The Company generally hedges its natural gas at the basis location that corresponds to the forecasted sale.

While the Company designates the majority of its hedges as cash flow hedges, it has not elected hedge accounting on certain of its crude oil and natural gas hedges. During the twelve months ended December 31, 2009, the Company recorded $6.5 million under the caption Gain (loss) on derivatives related to hedges for which it either did not elect hedge accounting or which no longer qualified for hedge accounting. In conjunction with the sale of the DJ basin assets, during the first quarter of 2009, the Company concluded that the forecasted transaction in certain of its hedging relationships was not probable of occurring. As such, the Company reclassified a gain of $14.3 million from AOCL to the Statement of Income under the caption Gain (loss) on derivatives. Gain (loss) on derivatives includes a loss for cash settlements of $7.6 million and a gain for the change in fair value of $0.3 million on hedges for which the Company has not elected hedge accounting. Additionally, a portion of the change in fair value for hedges that was designated as cash flow hedges may impact the Company s income as the sales price is not perfectly correlated with the Company s hedges. The Company recognized an unrealized net loss of $0.5 million on the Statement of Income under the caption Gain (loss) on derivatives for the twelve months ended December 31, 2009, respectively, as a result of ineffectiveness. During the first quarter of 2009, the Company entered into natural gas derivatives on behalf of the purchaser of its DJ assets. The Company did not elect hedge accounting for these hedges and recorded an unrealized net loss of $0.5 million on the Statement of Income under the caption (Loss) income from discontinued operations, net of taxes.

The Company s hedge contracts have been executed primarily with counterparties that are party to its senior secured revolving credit facility.

Neither the Company nor its counterparties are required to post collateral in connection with its derivative positions and netting agreements are in place with each of the Company s counterparties allowing the Company to offset its commodity derivative asset and liability positions. The credit rating of each of these counterparties was AA-/Aa2, or better as of December 31, 2009. The Company s derivatives are held with a small number of counterparties and as of December 31, 2009, the Company s largest three counterparties accounted for 76% of the value of its total derivative positions.

As of December 31, 2009, the Company had the following commodity hedges:

	2010	**2011**	**2012**
Oil Bbl/D:	14,930	9,020	3,000
Natural Gas MMBtu/D:	19,000	10,000	10,000

For further discussion related to the fair value of the Company s derivatives see Note 2 to the financial statements.

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4. Asset Retirement Obligations (AROs)

The following table summarizes the change in abandonment obligation for the years ended December 31 (in thousands):

		2009		2008
Beginning balance at January 1	$	41,967	$	36,426
Liabilities incurred		1,407		4,686
Liabilities settled		(1,030)		(4,607)
Disposition of assets		(2,752)		
Revisions in estimated liabilities				2,006
Accretion expense		3,895		3,456
Ending balance at December 31	$	43,487	$	41,967

The ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company s oil and gas properties. Inherent in the fair value calculation of the 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.

5. Acquisitions and Divestitures

During the twelve months ended December 31, 2009, the Company completed acquisitions totaling $13.5 million. In June 2009, the Company acquired property near McKittrick, California, the deep rights to one of the leases in its Darco property in E. Texas, and additional interests in its Piceance Garden Gulch assets.

On July 17, 2009, the Company completed the financing of its E. Texas gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term gas gathering agreements for the E. Texas production which contained an embedded lease. The transaction was treated as a financing obligation. Accordingly, the net book value of the property of $16.7 million will be depreciated over the remaining useful life of the asset and the cash received of $18.4 million was recorded as a financing obligation. A portion of future payments will be recorded as gathering expense, a portion as interest expense and the balance as a reduction in the financing obligation. There is no minimum payment required under these agreements.

On March 3, 2009, the Company entered into an agreement to sell its DJ basin assets and related hedges for $154 million before customary closing adjustments. The closing date of the sale of the assets was April 1, 2009. The Company recorded a pre-tax impairment loss of $9.6 million related to the sale, which is aggregated within the $5.9 million (Loss) income from discontinued operations, net of taxes on its Statement of Income for the twelve months ended December 31, 2009.

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(Loss) income from discontinued operations, net of tax on the accompanying statements of income is comprised of the following (in thousands):

	For the Twelve Months Ended December 31, 2009	2008	2007
Oil and gas revenue	$ 5,396	48,729	$ 34,192
Loss on sale of asset	(908)		
Other revenue	623	2,072	1,851
Total revenue	5,111	50,801	36,043
Operating expenses	2,576	11,340	10,279
Production taxes	195	3,023	2,564
DD&A	2,188	12,642	10,829
General and administrative	388	1,074	547
Interest expense	815	2,267	2,218
Commodity derivatives	484	145	13
Dry hole, abandonment, impairment and exploration	9,637	1,772	5,306
Total expenses	16,283	32,263	31,756
(Loss) income from discontinued operations, before income taxes	(11,172)	18,538	4,287
Income tax (benefit) expense	(5,234)	6,785	1,643
(Loss) income from discontinued operations	$ (5,938)	11,753	$ 2,644

On July 15, 2008, the Company acquired a 100% working interest in natural gas producing properties on 4,500 net acres in Limestone and Harrison counties in E. Texas for approximately $668 million, including post closing adjustments of $46 million.

The unaudited pro forma results presented below for the years ended December 31, 2008 and 2007 have been prepared to give effect to the E. Texas Acquisition on the Company s results of operations under the purchase method of accounting as if it had been consummated at the beginning of each of the periods presented. 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. The pro forma results set forth below also gives effect to (1) the presentation as discontinued operations of the Company s DJ Basin assets, which were sold on April 1, 2009, and (2) the Company s implementation of authoritative guidance on determining whether instruments granted in share-based payment transactions are participating securities, which requires the revision of prior period basic and diluted earning per share data.

	Year Ended December 31, 2008	Year Ended December 31, 2007
Pro forma revenue	$ 797,261	$ 581,138
Pro forma income from operations	$ 197,196	$ 162,733
Pro forma net income	$ 125,917	$ 103,333
Pro forma basic earnings per share	$ 2.79	$ 2.34
Pro forma diluted earnings per share	$ 2.75	$ 2.30

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The following is a calculation and allocation of purchase price to the E. Texas Acquisition assets and liabilities based on their relative fair values, as determined by the valuation of proved reserves and related assets as of the acquisition date:

Purchase price (in thousands):		**As of December 31, 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		45,506
Total purchase price allocation	$	667,862
Allocation of purchase price (in thousands):		
Oil and natural gas properties	$	651,659(i)
Pipeline		17,277
Tax receivable		1,476
Total assets acquired		670,412
Current liabilities		(1,195)(ii)
Asset retirement obligation		(1,355)
Net assets acquired	$	667,862

(i) Determined by reserve analysis.

(ii) Accrual for royalties payable.

In May 2007, the Company sold its non-core West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million and the Company recognized a $52 million pretax gain on the sale, including post closing adjustments. In the fourth quarter of 2007 the Company completed the sale of a portion of its Tri-State acreage for $1.4 million.

6. Oil and Gas Properties, Buildings and Equipment

Oil and gas properties, buildings and equipment consist of the following at December 31 (in thousands):

		2009		**2008**
Oil and gas:				
Proved properties:				
Producing properties, including intangible drilling costs	$	1,892,340	$	1,820,609
Lease and well equipment (1)		513,961		663,610
		2,406,301		2,484,219

Unproved properties				
Properties, including intangible drilling costs		267,303		255,412
		2,673,604		2,739,631
Less accumulated depreciation, depletion and amortization		583,077		509,277
		2,090,527		2,230,354
Commercial and other:				
Land		66		810
Drilling rigs and equipment		5,333		13,166
Buildings and improvements		5,911		6,274
Machinery and equipment		26,608		22,767
		37,918		43,017
Less accumulated depreciation		22,060		18,946
		15,858		24,071
	$	2,106,385	$	2,254,425

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(1) *Includes cogeneration facility costs.*

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Suspended Well Costs

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period of greater than one year since the completion of drilling (in thousands, except number of projects):

	2009	2008	2007
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$	$	$ 6,826
Capitalized exploratory well costs that have been capitalized for a period greater than one year			
Balance at December 31	$	$	$ 6,826
Number of projects that have exploratory well costs that have been capitalized for a period of greater than one year			

The following table reflects the net changes in capitalized exploratory well costs (in thousands):

	2009	2008	2007
Beginning balance at January 1	$	$ 6,826	$ 89
Additions to capitalized exploratory well costs pending the determination of proved reserves			6,826
Reclassifications to wells, facilities and equipment based on the determination of proved reserves		(6,826)	
Capitalized exploratory well costs charged to expense			(89)
Ending balance at December 31	$	$	$ 6,826

Dry hole, abandonment, impairment and exploration

In 2009 the Company had dry hole, abandonment and impairment charges of $5.2 million primarily due to a $4.2 million impairment charge related to the write-down of a rig to its fair market value (see Note 2 Fair Value Measurement). The Company incurred exploration costs in 2009 of $0.2 million compared to $0.6 million in 2008 and $0.6 million in 2007. These costs consist primarily of geological and geophysical costs.

In 2008 the Company had dry hole, abandonment, impairment and exploration charges of $10.5 million consisting primarily of $7.3 million 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. Due to the release of its rigs the Company performed an impairment test which resulted in $2.4 million of impairment costs resulting from the impairment of one rig.

In 2007 the Company had dry hole, abandonment, impairment and exploration charges of $8.4 million that consisted primarily of a $3.3 million impairment of its Coyote Flats prospect to reflect its fair value in conjunction with the preparation of its year end reserve estimates, a $2.9 million writedown of its Bakken properties which were sold in September 2007, geological and geophysical costs of $0.6 million and other dry hole charges of $1.6 million.

7. Debt Obligations

Short-term lines of credit

In 2005, the Company 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 the Company or the lender. In conjunction with the amendment to the Company s senior secured credit facility, on July 15, 2008, the Line of Credit was collateralized by oil and natural gas properties representing at least 80% of the present value of the Company s proved reserves.

At December 31, 2009 and 2008, the outstanding balance under this Line of Credit was zero and $25.3 million, respectively. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1.4%. The weighted average interest rate on outstanding borrowings on the Line of Credit at December 31, 2009 and 2008 was 0% and 1.4%, respectively.

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Senior secured revolving credit facility

The Company s senior secured revolving credit facility (the Agreement) has a current borrowing base and lender commitments of $938 million. The LIBOR and prime rate margins are between 2.25% and 3.0% based on the ratio of credit outstanding to the borrowing base and the annual commitment fee on the unused portion of the credit facility is 0.50%.

Covenants under the Agreement are as follows:

Total funded debt to EBITDAX (1) ratio not greater than:			**Senior secured debt to EBITDAX ratio not greater than:**			
2009	**2010**	**Thereafter**	**to Sep 2010**	**Mar 2011**	**Sep 2011**	**Thereafter**
4.75	4.50	4.00	3.75	3.50	3.25	3.0

(1) Net income before interest expense, income tax expense, depreciation and amortization expense, exploration expense and non-cash items of income.

The write off of $38.5 million to bad debt expense associated with the bankruptcy of BWOC is excluded from the calculation of EBITDAX, per the Agreement.

The Agreement contains a current ratio covenant which, as defined, must be at least 1.0. The total outstanding debt at December 31, 2009 under the Agreement, as amended, and the Line of Credit was $372 million and zero, respectively, and $4 million in letters of credit have been issued under the facility, leaving $562 million in borrowing capacity available. The maximum amount available is subject to semi-annual redeterminations of the borrowing base, based on the value of the Company s proved oil and gas reserves, in April and October of each year in accordance with the lenders customary procedures and practices. Both the Company and the banks have the bilateral right to one additional redetermination each year. The Agreement is collateralized by oil and natural gas properties representing at least 80% of the present value of the Company s proved reserves.

Second Lien Term Loan

On April 27, 2009 the Company completed a $140 million second lien term loan, with lenders from among its current lending group, with a maturity of January 16, 2013. The Company paid off the second lien term loan on May 29, 2009 from the proceeds of the issuance of its 10.25% senior notes due 2014, and wrote off $7.2 million in deferred loan fees for the year ended December 31, 2009.

10.25% senior notes due 2014

On May 27, 2009, the Company issued in a public offering $325 million principal amount of 10.25% senior notes due 2014 ($325 million Notes). Interest on the $325 million Notes is paid semiannually in June and December of each year. The $325 million Notes were issued at a discount to par value of 93.546%, and are carried on the balance sheet at their amortized cost. The deferred costs of approximately $9.5 million associated with the issuance of this debt are being amortized over the five year life of the $325 million Notes. Pursuant to the terms of the Company s senior secured revolving credit facility, the issuance of the $325 million Notes automatically reduced its borrowing base by 25 cents per dollar of Notes issued, or approximately $81 million. The Company wrote off $3.3 million of deferred loan fees during the second quarter of 2009 as a result of the decrease in its borrowing base.

On August 13, 2009, the Company issued in a public offering an additional $125 million principal amount of its 10.25% senior notes due 2014 ($125 million notes and, together with the $325 million notes, the Notes). The $125 million Notes were issued at a premium to par value of 104.75%, and are carried on the balance sheet at their amortized cost. The deferred costs of approximately $1.9 million associated with the issuance of this debt are being amortized over the five year life of the Notes. Pursuant to the terms of the Company s senior secured revolving credit facility, the issuance of the $125 million Notes automatically reduced its borrowing base by 25 cents per dollar of notes issued, or approximately $31 million. The Company wrote off $0.3 million of deferred loan fees during the third quarter of 2009 as a result of the decrease in its borrowing base.

The $125 million Notes and the previously issued $325 million Notes are treated as a single series of debt securities and are carried on the balance sheet at their combined amortized cost.

8.25% senior subordinated notes due 2016

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

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approximately $5.2 million associated with the issuance of this debt are being amortized over the ten year life of the Sub notes.

Financial Covenants

The senior secured revolving credit facility contains restrictive covenants as described above. Under the Company s senior subordinated and senior unsecured notes as long as the interest coverage ratio (as defined) is greater than 2.5 times, the Company may incur additional debt. The Company was in compliance with all of these covenants as of December 31, 2009.

	As of December 31, 2009
Current Ratio (Not less than 1.0)	5.5
Total Funded Debt Ratio to EBITDAX (Not greater than 4.75)	3.3
Interest Coverage Ratio (Not less than 2.5)	4.2
Senior Secured Debt Ratio to EBITDAX (Not greater than 3.75)	1.2

The weighted average interest rate on the Company s total outstanding borrowings was 7.0% and 4.9% at December 31, 2009 and 2008, respectively.

8. Income Taxes

The continuing operations provision for income taxes consists of the following (in thousands):

	2009	**2008**	**2007**
Current:			
Federal	$ 2,388	$ 2,991	$ 12,676
State	(198)	5,285	5,191
	2,190	8,276	17,867
Deferred:			
Federal	28,221	56,919	52,235
State	(2,062)	5,113	8,958
	26,159	62,032	61,193
Total	$ 28,349	$ 70,308	$ 79,060

The following table summarizes the components of the total deferred tax assets and liabilities. The components of the net deferred tax liability consist of the following at December 31 (in thousands):

	2009	**2008**

Deferred tax asset:				
Federal benefit of state taxes	$	6,064	$	11,082
Credit carryforwards		27,729		33,636
Stock option costs		11,091		9,089
Derivatives		42,218		2,282
Bad debt expense		15,605		15,936
Other, net		1,807		4,312
		104,514		76,337
Deferred tax liability:				
Depreciation and depletion		(330,836)		(319,349)
Derivatives		(5,216)		(72,801)
		(336,052)		(392,150)
Net deferred tax liability	$	(231,538)	$	(315,813)

At December 31, 2009, the Company s net deferred tax assets and liabilities were recorded as a current asset of $5.6 million and a long-term liability of $237.2 million. At December 31, 2008, the Company s net deferred tax assets and liabilities were recorded as a current liability of $45.5 million and a long-term liability of $270.3 million.

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Reconciliation of the continuing operations statutory federal income tax rate to the effective income tax rate follows:

	2009	2008	2007
Tax computed at statutory federal rate	35%	35%	35%
State income taxes, net of federal benefit	4	3	5
Deferred state rate impact	(4)	(1)	
Net impact to uncertain tax positions	(2)		
Other	(1)	(1)	(2)
Effective tax rate	32%	36%	38%

The Company has approximately $14 million of federal and $15 million of state (California) EOR tax credit carryforwards available to reduce future income taxes. The EOR credits will begin to expire, if unused, in 2024 and 2016 for federal and California purposes, respectively.

In June 2006, the FASB issued authoritative guidance on accounting for uncertainty in income taxe*s*. The guidance addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. The Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. There is also guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires additional disclosures.

As of December 31, 2009, the Company had a gross liability for uncertain tax benefits of $6.1 million of which $5.2 million, if recognized, would affect the effective tax rate. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. The Company had accrued approximately $0.7 million and $1.2 million of interest related to its uncertain tax positions as of December 31, 2009 and 2008, respectively.

For the year ended December 31, 2009 the Company recognized a net benefit of approximately $4.0 million to the Statements of Income due to audit settlements and the closure of certain federal and state tax years and uncertain tax positions accruals, net of interest expense, of approximately $0.8 million.

For the year ended December 31, 2008 the Company recognized a net benefit of approximately $1.6 million to the Statements of Income due to the closure of certain federal and state tax years, offset by additional uncertain tax position accruals net of interest expense of approximately $1.9 million.

For the year ended December 31, 2007 the Company recognized a net benefit of approximately $0.6 million to the Statements of Income due to the closure of certain federal and state tax years, offset by additional uncertain tax position accruals net of interest expense of approximately $0.2 million.

The following table illustrates changes in the gross unrecognized tax benefits (in millions):

	2009	2008	2007
Unrecognized tax benefits at January 1	$ 12.0	$ 12.0	$ 14.6
(Decreases) increases for positions taken in current year	(0.1)	1.2	0.5
(Decreases) increases for positions taken in a prior year	(1.3)	0.3	(0.3)
Decreases for settlements with taxing authorities	(3.6)		
Decreases for lapses in the applicable statute of limitations	(0.9)	(1.5)	(2.8)
Unrecognized tax benefits at December 31	$ 6.1	$ 12.0	$ 12.0

As of December 31, 2009, the Company remains subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction:	**Tax Years Subject to Exam:**
Federal	2005 2008
California	2005 2008
Colorado	2005 2008
Utah	2005 2008

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9. Earnings Per Share

In June 2008, the FASB issued authoritative guidance, which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method. All prior period earnings per share data presented were adjusted retrospectively to conform with the provisions of the guidance which is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years.

The following table shows the computation of basic and diluted net (loss) income per share from continuing and discontinued operations for the years ended December 31, (in thousands):

	2009	2008	2007
Net income from continuing operations	$ 59,968	$ 121,776	$ 127,284
Less: Income allocable to participating securities	1,460	1,752	1,494
Income available for shareholders	$ 58,508	$ 120,024	$ 125,790
Net (loss) income from discontinued operations	$ (5,938)	$ 11,753	$ 2,644
Less: Income allocable to participating securities		173	32
Loss (income) from discontinued operations available for shareholders	$ (5,938)	$ 11,580	$ 2,612
Basic earnings per share from continuing operations	$ 1.31	$ 2.70	$ 2.85
Basic (loss) earnings per share from discontinued operations	(0.13)	.26	.06
Basic earnings per share	$ 1.18	$ 2.96	$ 2.91
Dilutive earnings per share from continuing operations	$ 1.30	$ 2.66	$ 2.81
Dilutive (loss) earnings per share from discontinued operations	(0.13)	.26	.06
Basic) earnings per share	$ 1.17	$ 2.92	$ 2.87
Weighted average shares outstanding - basic	44,625	44,485	44,075
Add: dilutive effects of stock options	221	578	604
Weighted average shares outstanding - dilutive	44,846	45,063	44,679

Options to purchase $1.6 million, $0.2 million and $0.0 million shares were not included in the diluted (loss) earnings per share calculation for the years ended December 31, 2009, 2008 and 2007, respectively, because their effect would have been anti-dilutive.

The adoption of the guidance issued by the FASB decreased basic earnings per share from continuing operations by $0.4 and $0.4 for the years ended December 31, 2008 and 2007, respectively, and dilutive earnings per share from continuing operations by $0.2 and $0.2 for the years ended December 31, 2008 and 2007, respectively. Basic and dilutive (loss) earnings per share from discontinued operations remained unchanged for the year ended December 31, 2008 and 2007.

10. Shareholders Equity

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the Capital Stock, are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $0.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Common Stock at the option of the holder.

Dividends

The regular annual dividend is currently $0.30 per share, payable quarterly in March, June, September and December.

Dividend payments are limited by covenants in the Company s (1) credit facility to the greater of $20 million or 75% of net income, and (2) bond indenture of up to $20 million annually irrespective of its coverage ratio or net income if the Company has exhausted its restricted payments basket, and up to $10 million in the event it is in a non-payment default.

Shareholder Rights Plan

In November 1999, the Company adopted a Shareholder Rights Agreement and declared a dividend distribution of one Right for each outstanding share of Capital Stock on December 8, 1999. The plan expired on December 8, 2009. No rights were exercised under the plan.

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11. Equity Incentive Compensation Plans and Other Benefit Plans

In December 1994, the Company s Board of Directors adopted the Berry Petroleum Company 1994 Stock Option Plan which was restated and amended in December 1997 and December 2001 (the 1994 Plan or Plan) and approved by the shareholders in May 1998 and May 2002, respectively. The 1994 Plan provided for the granting of stock options to purchase up to an aggregate of 3,000,000 shares of Common Stock. All options, with the exception of the formula grants to non-employee Directors, were granted at the discretion of the Compensation Committee and the Board of Directors. The term of each option did not exceed ten years from the date the options were granted. The 1994 Plan expired in December 2004, and the shareholders approved a new equity incentive plan in May 2005.

The 2005 Equity Incentive Plan (the 2005 Plan), approved by the shareholders in May 2005, provides for granting of equity compensation up to an aggregate of 2,900,000 shares of Common Stock. All equity grants are at market value on the date of grant and at the discretion of the Compensation Committee or the Board of Directors. The term of each grant did not exceed ten years from the grant date, and vesting has generally been at 25% per year for 4 years or 100% after 3 years. The 2005 Plan also allows for grants to non-employee Directors although no grants were made to non-employee directors in 2008 or 2009. The grants made to the non-employee Directors under the 2005 plan vest immediately. The Company uses a broker for issuing new shares upon option exercise.

Total compensation cost recognized in the Statements of Income was $7.7 million, $8.9 million and $8.4 million in 2009, 2008 and 2007, respectively. The tax benefit related to this compensation cost was $3.2 million, $3.8 million and $3.3 million in 2009, 2008 and 2007, respectively.

Stock Options

The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model that uses the assumptions noted in the following table. Expected volatilities are based on the historical volatility of the Company s stock. The Company uses historical data to estimate option exercises and employee terminations within the valuation model; separate groups of recipients that have similar historical exercise behavior are considered separately for valuation purposes. The expected term of options granted is based on historical exercise behavior and represents the period of time that options granted are expected to be outstanding; the range given below results from certain groups of recipients exhibiting different exercise behavior. The risk free rate for periods within the contractual life of the option is based on U.S. Treasury rates in effect at the time of grant. During 2009, no options were granted.

	2009	**2008**	**2007**
Expected volatility		36%	32% - 33%
Weighted-average volatility		36%	33%
Expected dividends		1%	1%
Expected term (in years)		5	4.9 - 5.6
Risk-free rate		3.2%	3.4% - 4.7%

The following table summarizes information related to stock options outstanding and exercisable as of December 31, 2009:

Range of Exercise Prices	Options Outstanding		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
$7.00 - $15.00	645,100	$	10.55	3.5	645,100	$	10.55	3.5
$15.01 - $25.00	436,250		21.61	4.9	436,250		21.61	4.9
$25.01 - $35.00	881,051		31.87	6.5	791,475		31.81	6.5
$35.01 - $45.00	313,619		42.74	8.1	135,500		43.20	8.1
Total	2,276,020	$	25.36	5.6	2,008,325	$	23.53	5.6

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Weighted average option exercise price information for the years ended December 31:

	2009	2008	2007
Outstanding at January 1	$ 25.16	$ 24.33	$ 20.97
Granted during the year		41.18	43.40
Exercised during the year	13.52	19.38	12.52
Cancelled/expired during the year	28.48	29.66	22.88
Outstanding at December 31	25.36	25.16	24.33
Exercisable at December 31	23.53	21.70	19.88

The following is a summary of stock option activity for the years ended December 31:

	2009	2008	2007
Balance outstanding, January 1	2,421,650	2,527,266	2,859,836
Granted		89,084	220,115
Exercised	(62,050)	(149,950)	(444,216)
Canceled/expired	(83,580)	(44,750)	(108,469)
Balance outstanding, December 31	2,276,020	2,421,650	2,527,266
Balance exercisable at December 31	2,008,325	1,842,532	1,558,780
Available for future grant	218,635	412,025	988,798
Weighted average remaining contractual life (years)	5.6	6.5	7.3
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$	$ 14.03	$ 13.88

As of December 31, 2009, there was $2.4 million of total unrecognized compensation cost related to stock options granted under the Plan. This cost is expected to be recognized over a weighted-average period of 1.3 years. The tax benefit realized from stock options exercised during the year ended December 31, 2009, 2008 and 2007 is $0.1 million, $1.4 million and $3.5 million, respectively.

		Stock Options Years ended	
	December 31, 2009	December 31, 2008	December 31, 2007
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$	$ 14.03	$ 13.88
Total intrinsic value of options exercised (in millions)	0.6	4.4	11.9
Total intrinsic value of options outstanding (in millions)	15.3		50.8
Total intrinsic value of options exercisable (in millions)	15.3		38.3

Restricted Stock Units

Under the 2005 Equity Plan, the Company began a long-term incentive program whereby restricted stock units (RSUs) are available for grant to certain employees and non-employee Directors. Granted RSUs generally vest at either 25% per year over 4 years or 100% after 3 years. Unearned compensation under the restricted stock award plan is amortized over the vesting period. During 2009 and 2008, the non-employee Directors did not receive any RSUs. The RSUs granted to the non-employee Directors are 100% vested at date of grant but are subject to a deferral election before the corresponding shares are issued of a minimum of four years or until they leave the Board of Directors or upon change of control. The Company pays cash compensation on the RSUs in an equivalent amount of actual dividends paid on a per share basis of its outstanding common stock.

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The following is a summary of RSU activity for the year ended December 31, 2009:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	966,198	$ 20.83	3.0 years
Granted	294,504	26.72	
Converted	(107,375)	28.98	
Canceled/expired	(46,034)	25.08	
Balance outstanding, December 31	1,107,293	$ 22.14	2.6 years

	RSUs Year ended December 31, 2009	2008	2007
Weighted-average grant date fair value of RSUs issued	26.72	$ 11.26	$ 42.36
Total value of RSUs vested (in millions)	2.6	0.8	2.1

The total compensation cost related to nonvested awards not yet recognized on December 31, 2009 is $12.6 million and the weighted average period over which this cost is expected to be recognized is 1.6 years.

Other Employee Benefits - 401(k) Plan

The Company sponsors a defined contribution thrift plan under section 401(k) of the Internal Revenue Code to assist all employees in providing for retirement or other future financial needs. In December 2005, the 401(k) Plan was amended whereby effective January 1, 2006, the Company s matching contribution is $1.00 for each $1.00 contributed by the employee up to 8% of an employee s eligible compensation. The Company s contributions to the 401(k) Plan, net of forfeitures, were $1.4 million for each of the years ended December 31, 2009, 2008 and 2007. Employees are eligible to participate in the 401(k) Plan on their date of hire and approximately 97% of the Company s employees participated in the 401(k) Plan in 2009.

Director Deferred Compensation Plan

The Company established a non-employee director deferred stock and compensation plan to permit eligible directors, in recognition of their contributions to the Company, to receive compensation for service and to defer recognition of their compensation in whole or in part to a Stock Unit Account or an Interest Account. When the eligible director ceases to be a director, the distribution from the Stock Unit Account shall be made in shares using an established market value date. The distribution from the Interest Account shall be made in cash. The plan may be amended at any time, but not more than once every six months, by the Compensation Committee or the Board of Directors. Shares earned and deferred in accordance with the plan as of December 31, 2009, 2008 and 2007 were 124,686, 24,204 and 12,934, respectively.

Amounts allocated to the Stock Unit Account have the right to receive an amount equal to the dividends per share the Company declares as applicable. The dividend payment date and this dividend equivalent shall be treated as reinvested in an additional number of units and credited to their account using an established market value date. Amounts allocated to the Interest Account are credited with interest at an established interest rate.

12. Concentration of Credit Risks

Significant Customers

The Company sells oil, gas and natural gas liquids to pipelines, refineries and oil companies and electricity to utility companies. Credit is extended based on an evaluation of the customer s financial condition and historical payment record. The Company does not believe that the loss of any one customer would impact the marketability, but it may impact the profitability of its crude oil, gas, natural gas liquids or electricity sold. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the crude oil sales customer could impact the marketability of a portion of the Company s Utah crude oil volumes.

In 2009, sales to three purchasers were approximately 25%, 16% and 12%of the Company s revenue. In 2008, sales to two purchasers were approximately 60% and 11% of the Company s revenue. In 2007, sales to one purchaser was approximately 68% of the Company s revenue.

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As of both December 31, 2009 and 2008 the Company has an allowance for doubtful accounts of $38.5 million, which represents the Company s November and December 2008 sales to BWOC. While the Company believes that it may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided the Company with any data from which to make a conclusion that any amounts will be collected.

Concentrations of Market Risk

The future results of the Company s oil and gas operations will be affected by the market prices of oil and gas. The availability of a ready market for crude oil, natural gas and liquid products in the future will depend on numerous factors beyond the Company s control, including weather, imports, proximity and capacity of oil and gas pipelines and other transportation facilities, any oversupply or undersupply of oil, gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

During 2009, the Company did not have any credit losses on the sale of oil, natural gas, natural gas liquids or hedging contracts. During 2008, the Company experienced two credit losses related to its oil and natural gas sales. Included in bad debt expense in 2008 is $0.2 million related to the bankruptcy of SemGroup and $38.5 million related to BWOC as described above. During 2007 the Company did not have any credit losses on the sale of oil, natural gas, natural gas liquids or hedging contracts.

The Company places its temporary cash investments with high quality financial institutions and limit the amount of credit exposure to any one financial institution. For the three years ended December 31, 2009, the Company has not incurred losses related to these investments.

Concentrations of Credit Risk

Derivative financial instruments that hedge the price of oil and gas and interest rate levels are generally executed with major financial or commodities trading institutions which expose us to market and credit risks and may, at times, be concentrated with certain counterparties or groups of counterparties. As of December 31, 2009, $74 million of the approximate net value of the Company s hedging positions of approximately $97 million can be attributed to one of three counterparties. While a significant portion of its hedges are with a small number of counterparties, the Company monitors each counterparty s credit rating and CDS rate. Neither the Company nor its counterparties are required to post collateral under the Company s hedging contracts.

13. Commitments and Contingencies

The Company s contractual obligations not included in its Balance Sheet as of December 31, 2009 (except Long-term debt and Abandonment obligations) are as follows (in millions):

	Total	2010	2011	2012	2013	2014	Thereafter
Long-term debt and interest	$ 1,359.7	$ 71.9	$ 71.9	$ 437.3	$ 62.6	$ 485.7	$ 230.3
Abandonment obligations	43.5	2.8	2.8	2.9	2.9	2.8	29.3
Operating lease obligations	16.0	2.4	2.4	2.5	2.5	2.5	3.7
Drilling and rig obligations	52.1	13.9	27.7	2.1	2.1	6.3	
Firm natural gas transportation contracts	136.8	19.7	19.7	17.9	15.7	14.8	49.0
Total	$ 1,608.1	$ 110.7	$ 124.5	$ 462.7	$ 85.8	$ 512.1	$ 312.3

Operating leases

The Company leases corporate and field offices in California, Colorado and Texas. Rent expense with respect to its lease commitments for the years ended December 31, 2009, 2008 and 2007 was $2.1 million, $1.7 million and $1.5 million, respectively. In 2006, the Company purchased an airplane for business travel which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

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Drilling obligations

The Company amended and restated its Utah Lake Canyon project in December 2009 and has a 14 gross well drilling commitment over the amended term (December 2009 to December 2014). The Company s minimum obligation under its exploration and development agreement is $14.7 million as of December 31, 2009. Also included above the Company has contractual obligations on its Piceance assets in Colorado. The Company must spud 120 wells by February 2011 to avoid penalties of $0.2 million per well. The Company expects to meet all obligations but its ability to meet this commitment depends on the capital resources available to the Company to fund its activities to develop these assets on the schedule required to avoid penalties or loss of related leases.

Other Commitments

On July 17, 2009, the Company closed on the financing of its E. Texas gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term gas gathering agreements for the E. Texas production which contained an embedded lease. There is no minimum payment required under these agreements. For the year ended 2009, the Company has incurred $2.0 million under the agreements.

On June 17, 2009, the Company amended its natural gas firm transportation agreement with Enbridge Pipelines providing for transportation of its gas from Tex-OK to Orange County, Florida (Zone 1). The agreement provides for minimum volume of 25,000 MMBtu/d and a maximum volume of 55,000 MMBtu/D.

The Company has two long-term firm transportation contracts that total 35,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. The Company pays a demand charge for this capacity and its own production did not completely fill that capacity. To maximize the utilization of its firm transportation, the Company bought its partners share of the gas produced in the Piceance basin at the market rate for that area and used its excess transportation to move this gas to the sales point. The pre-tax net of its gas marketing revenue and its gas marketing expense in the Statements of Operations is $1.6 million, $3.7 million and $0 for the years ended December 31, 2009, 2008 and 2007, respectively.

In addition, Berry has signed two precedent agreements 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. A component of these agreements is currently in dispute and may result in a termination of the contracts for capacity on this pipeline in which case the Company will make alternative arrangements for the transportation and marketing of the Company s production. The Company does not believe the termination of these contracts will result in monetary damages. Please see Item 1A. Risk Factors If third-party pipelines interconnected to our natural gas wells and gathering facilities become partially or fully unavailable to transport our natural gas, our results of operations and financial condition could be adversely affected.

The Company is a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of a minimum of 5,000 Bbl/D of its Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company s 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company s crude oil. Gross oil production from the Company s Uinta properties averaged approximately 2,700 Bbl/D in 2009. Please see Item 1A. Risk Factors We may not be able to deliver minimum crude oil volumes required by our sales contract.

In December 2008, Flying J, Inc., and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company s California production. Included in the allowance for doubtful accounts is $38.5 million due from BWOC. Of the $38.5 million due from BWOC, $11.8 million represents 20 days of the Company s December 2008 crude oil sales, an administrative claim under the bankruptcy proceedings, and $26.7 million represents November 2008 and the balance of December 2008 crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract. The Company has guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that the claim is not fully collectible from BWOC. While the Company believes that it may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided the Company with adequate data from which to make a conclusion that any amounts will be collected.

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The Company has no material accrued environmental liabilities for its sites, including sites in which governmental agencies have designated the Company 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. The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material effect on its financial position, or on the results of operations or liquidity.

Certain of the Company s royalty payment calculations are being disputed. The Company believes that its royalty calculations are in accordance with applicable leases and other agreements. However, the disputed amounts that it may be required to pay are up to approximately $6 million.

In July 2009, the Company received a notice of proposed civil penalty from the Bureau of Land Management (BLM) related to the Company s alleged non-compliance during 2007 with regulations relating to the operation and position of certain valves in its Uinta basin operations. The proposed civil penalty was $69.6 million and reflects the theoretical maximum penalty amount under applicable regulations, absent mitigating factors. In 2007 the Company immediately remediated the instances of non-compliance, cooperated fully with the BLM s investigation and the Company believes no production was lost, all royalties were paid and there was no harm to the environment. Due to the above mitigating factors, among others, the Company believes this matter will be resolved by the payment of a penalty that will not exceed $2.1 million and accrued such amount in the second quarter of 2009.

During the California energy crisis in 2000 and 2001, the Company had electricity sales contracts with various utilities and a portion of the electricity prices paid to the Company under such contracts from December 2000 to March 27, 2001 has been under a degree of legal challenge since that time. It is possible that the Company may have a liability pending the final outcome of the CPUC proceedings on the matter. There are ongoing proceedings before the CPUC in which Edison and PG&E are seeking credit against future payments they are to make for electricity purchases based on retroactive adjustments to pricing under contracts with the Company. Whether or not retroactive adjustments will be ordered, how such adjustments would be calculated and what period they would cover are too uncertain to estimate at this time.

As of December 31, 2009, the Company had a gross liability for uncertain tax benefits of $6.1 million and an additional $0.7 million of interest related to its uncertain tax positions. At this time, the Company is unable to make a reasonably reliable estimate of the timing of payments in individual years due to uncertainties in the timing of tax audit outcomes; therefore, such amounts are not included in the above contractual obligation table.

14. Subsequent Events

The Company evaluates subsequent events through the date the financial statements are issued, which for the annual period ended December 31, 2009, is February 25, 2010.

Effective January, 2010, the Company has elected to de-designate all of its commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively.

In January 2010, the Company entered into an agreement with a private seller to acquire interests in producing properties principally in the Wolfberry trend in West Texas for approximately $126 million in cash. The effective date of the transaction is January 1, 2010. Closing is expected in March 2010.

In January 2010, the Company completed the sale of 8,000,000 shares of its Class A Common Stock at $29.25 per share. Net proceeds from the sale of common stock, after deducting estimated underwriting discounts and commissions and offering expenses, was $224.3 million. Net proceeds from the offering are expected to be used to fund the planned acquisition of certain properties in the Wolfberry trend of W. Texas and for general corporate purposes. Pending the application of the proceeds for such purposes, the Company used the net proceeds to reduce outstanding borrowings under its senior secured revolving credit facility.

In February 2010, the Company entered into an agreement with a private seller to acquire interests in producing properties in the Wolfberry trend in W. Texas for approximately $14 million cash.

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15. Quarterly Financial Data (Unaudited)

The following is a tabulation of unaudited quarterly operating results for 2009 and 2008 (in thousands, except per share data) and has been updated to reflect (1) the presentation as discontinued operations of the Company s natural gas assets in the Denver-Julesburg basin in Colorado (the DJ Basin assets), and (2) the Company s implementation of authoritative guidance for determining whether instruments granted in share-based payment transactions are participating securities, which requires the revision of prior period basic and diluted earnings per share data.

	Operating Revenues	Income (Loss) From Continuing Operations	Income (Loss) from Discontinued Operations	Net Income (Loss)	Basic Net Income(Loss) From Continuing Operations Per Share	Basic Net Income(Loss) From Discontinued Operations Per Share	Diluted Net Income(Loss) From Continuing Operations Per Share	Diluted Net Income(Loss) From Discontinued Operations Per Share
2009								
First Quarter	$ 145,720	$ 41,779	$ (6,781)	$ 34,998	$ 0.92	$ (0.15)	$ 0.92	$ (0.15)
Second Quarter (1)	130,265	(12,768)	(212)	(12,980)	(0.28)		(0.28)	
Third Quarter	141,809	18,339	668	19,007	0.41	0.01	0.40	0.01
Fourth Quarter (2)	147,768	12,618	387	13,005	0.28	0.01	0.28	0.01
	$ 565,562	$ 59,968	$ (5,938)	$ 54,030	$ 1.31	$ (0.13)	$ 1.30	$ (0.13)
2008								
First Quarter	$ 170,824	$ 39,536	$ 3,495	$ 43,031	$ 0.88	$ 0.08	$ 0.86	$ 0.08
Second Quarter	197,532	43,712	5,429	49,141	0.97	0.12	0.95	0.12
Third Quarter	225,491	49,615	3,733	53,348	1.10	0.08	1.08	0.08
Fourth Quarter (3)	154,676	(11,087)	(904)	(11,991)	(0.24)	(0.02)	(0.24)	(0.02)
	$ 748,523	$ 121,776	$ 11,753	$ 133,529	$ 2.70	$ 0.26	$ 2.66	$ 0.26

(1) Includes an unrealized pre-tax non-cash loss on derivatives of $31.1 million, a pre-tax charge of $10.5 million for debt extinguishment costs and a liability for a regulatory compliance matter of $2.1 million.

(2) Included in the fourth quarter of 2009 are adjustments to correct the prior accounting for the Company s royalties in the amount of $3.3 million, which resulted in decreasing its sales of oil and gas and increasing its royalties payable. Management concluded the impact was immaterial to the current and prior periods. Also included in the fourth quarter of 2009 is an impairment charge of $4.2 million related to the write-down of a rig.

(3) Includes $38.5 million of bad debt expense related to the allowance for bad debt taken for the bankruptcy of BWOC.

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16. Supplemental Information About Oil & Gas Producing Activities (Unaudited)

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-03 *Extractive Activities Oil and Gas (Topic) 932.* The ASU amends previously issued authoritative guidance. The objective of the amendments included in the ASU is to align the oil and gas reserves estimation and disclosure requirements with the requirements of the Securities and Exchange Commission (SEC). The new guidance, among other purposes, is primarily intended to provide investors with

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a more meaningful and comprehensive understanding of oil and gas producing activities, updating the definition of proved oil and gas reserves to indicate that entities must use the average, first-day-of-the-month price during the 12-month period before the ending date of the period covered by the report, disclosing geographical areas that represent a certain percentage of proved reserves, updating the reserve estimation requirements for changes in practice and technology that have occurred over the past several decades and requiring an entity to disclose separately the amounts and quantities for consolidated and equity method investments. The Company has applied this guidance to its Financial Statements for the year-ended December 31, 2009. The new oil and gas reserve measurement and reporting requirements were adopted for oil and gas reserves as of December 31, 2009. For accounting purposes, the new requirements constitute a change in accounting principle inseparable from a change in estimate. Prior reserve disclosures were not modified and the impact of the new requirements on our oil and gas reserves was reflected as a change in estimate. Changes in reserves estimates are applied on a prospective basis.

The following sets forth costs incurred for oil and gas property acquisition, development and exploration activities, whether capitalized or expensed (in thousands):

		2009		**2008**		**2007**
Property acquisitions						
Proved properties	$	13,497	$	667,996	$	
Unproved properties						56,247
Development (1)		138,168		385,599		278,398
Exploration (2)		30,316		32,909		23,325
	$	181,981	$	1,086,504	$	357,970

(1) Development costs include $4.9 million, $0.1 million and $1.2 million charged to expense during 2009, 2008 and 2007, respectively.

(2) Exploration costs include $0.2 million, $2.4 million and $5.2 million that were charged to expense during 2009, 2008 and 2007, respectively. Exploration costs include $30.1 million $23.2 million and $18.1 million of capitalized interest in 2009, 2008 and 2007, respectively.

The following estimates of proved oil and gas reserves, both developed and undeveloped, represent the Company s owned interests located solely within the United States. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved developed are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

For the years ended December 31, 2009, 2008 and 2007 the Company engaged DeGolyer and McNaughton (D&M) to estimate its proved oil and gas reserves and the future net revenue to be derived from its properties. D&M is an independent petroleum engineering consulting firm has provided consulting services throughout the world for over 70 years.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond the Company s control. Reserve engineering is a process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition to the physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, economic factors such as changes in product prices or development and production expenses, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates. These estimates do not include probable or possible reserves. The information provided does not represent management s estimate of its expected future cash flows or value of proved oil and gas reserves.

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Changes in estimated reserve quantities

The net interest in estimated quantities of proved developed and undeveloped reserves of crude oil and natural gas at December 31, 2009, 2008 and 2007, and changes in such quantities during each of the years then ended were as follows (in thousands):

		2009			**2008**			**2007**	
	Oil Mbbl	**Gas MMcf**	**MBOE**	**Oil Mbbl**	**Gas MMcf**	**MBOE**	**Oil Mbbl**	**Gas MMcf**	**MBOE**
Proved developed and Undeveloped reserves:									
Beginning of year	125,251	724,135	245,940	116,602	315,464	169,179	112,538	226,363	150,262
Revision of previous estimates	2,786	(34,564)	(2,975)	(10,211)	(41,570)	(17,139)	(3,826)	3,358	(3,262)
Improved recovery				7,600		7,600	4,500		4,500
Extensions and discoveries	8,989	54,664	18,100	18,700	145,800	43,000	17,300	101,400	34,200
Property sales		(126,600)	(21,100)				(6,700)		(6,700)
Production	(7,186)	(22,657)	(10,962)	(7,440)	(25,559)	(11,700)	(7,210)	(15,657)	(9,819)
Purchase of reserves in place	100	37,200	6,300		330,000	55,000			
End of year	129,940	632,178	235,303	125,251	724,135	245,940	116,602	315,464	169,179
Proved developed reserves:									
Beginning of year	74,616	361,575	134,879	78,339	147,346	102,897	84,782	104,934	102,270
End of year	82,870	255,520	125,456	74,616	361,575	134,879	78,339	147,346	102,897

The standardized measure has been prepared using the average price during the 12 month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions, and year-end costs, assuming statutory tax rates (adjusted for tax credits and other items), and a ten percent annual discount rate**.** No deduction has been made for depletion, depreciation or any indirect costs such as general corporate overhead or interest expense. Cash outflows for future production and development costs include those cash flows associated with the ultimate settlement of the asset retirement obligation.

Excluding the effect of production and property sales, reserves increased 21.5 million BOE from 2008 to 2009. The reserves increased 18 million BOE from the Company s drilling and completion activities and 6 million BOE from acquisitions. The acquisition reserves include the 6 million BOE purchase in the Piceance Basin. The 18 million BOE increase resulting from the Company s drilling and completion activities were primarily at its Diatomite fields in California and its fields in the Piceance Basin. Reserve revisions across the company resulted in a decrease of 3 million BOE due to performance. Specifically, the decrease is attributable to a 1 million BOE increase in California, a 5 million BOE increase in the Rockies, offset by a 9 million BOE decrease in East Texas.

The reserve sales of 21 million BOE resulted from the sale of the Company s DJ basin reserves.

Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves (in thousands):

	2009	2008	2007
Future cash inflows	$ 9,028,991	$ 7,384,692	$ 11,211,151
Future production costs	(3,826,832)	(2,920,664)	(3,275,397)
Future development costs	(1,159,465)	(1,196,394)	(812,070)
Future income tax expense	(969,771)	(511,291)	(2,286,296)
Future net cash flows	3,072,923	2,756,343	4,837,388
10% annual discount for estimated timing of cash flows	(1,627,176)	(1,620,762)	(2,417,882)
Standardized measure of discounted future net cash flows	$ 1,445,747	$ 1,135,581	$ 2,419,506
Average sales prices at December 31: (a)			
Oil ($/Bbl)	$ 52.06	$ 30.03	$ 79.19
Gas ($/Mcf)	$ 3.58	$ 4.85	$ 6.27
BOE Price	$ 38.37	$ 30.92	$ 66.27

(a) The new SEC and FASB reserves reporting rules require the use of 12-month average commodity prices effective for 2009, instead of year-end commodity prices used in 2008 and 2007.

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Changes in standardized measure of discounted future net cash flows from proved oil and gas reserves (in thousands):

	2009	2008	2007
Standardized measure - beginning of year	$ 1,135,581	$ 2,419,506	$ 1,182,268
Sales of oil and gas produced, net of production costs	(353,052)	(497,866)	(326,174)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	637,882	(2,686,941)	1,451,140
Revisions of previous quantity estimates	(33,943)	(144,466)	(78,758)
Improved recovery		64,058	108,655
Extensions and discoveries	206,542	362,435	825,775
Change in estimated future development costs	(52,824)	(352,061)	(286,439)
Purchases of reserves in place	29,348	667,862	
Sales of reserves in place	(138,265)		(98,680)
Development costs incurred during the period	110,200	173,184	132,002
Accretion of discount	131,745	354,672	162,257
Income taxes	(190,727)	631,372	(687,103)
Other	(36,740)	143,826	34,563
Net increase (decrease)	310,166	(1,283,925)	1,237,238
Standardized measure - end of year	$ 1,445,747	$ 1,135,581	$ 2,419,506

17. Correction of Other Comprehensive Income (Loss)

The Company noted a presentation error in the Statements of Comprehensive Income (Loss) and the related disclosures in Note 3 to the audited financial statements contained in the Company s Annual Report on Form 10-K for the year ended December 31, 2009. The Company has concluded that the presentation error was immaterial to the audited financial statements contained in the 2009 Form 10-K. The effects of the presentation error are summarized in the tables below:

The components of comprehensive income (loss):

	For the twelve months ended December 31, 2009	
	As Previously Reported	As Revised (1)
Net Income	$ 54,030	$ 54,030
Unrealized gains (losses) on derivatives, net of income taxes	205,318	(129,287)
Reclassification of realized (gains) losses, net of income taxes	(31,249)	(44,782)
Comprehensive income (loss)	$ 228,099	$ (120,039)

The table below contained in Note 3 to the audited financial statements summarizes the impacts of the Company s derivative instruments gains (losses) before income taxes reported in the Statements of Income (Loss) and the Statement of Comprehensive Income (Loss) for the twelve months ended December 31, 2009:

Previously Reported

Derivatives cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCL on Derivative (Effective portion)	Location of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Location of Gain (loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain (Loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
Commodity - Oil	$ (222.3)	Sales of oil and gas	$ 53.9	Sales of oil and gas	$
Commodity - Natural Gas	(18.6)	Sales of oil and gas	11.1	Gain (loss) on derivatives	13.7
Interest rate	8.8	Interest expense	(7.0)	Gain (loss) on derivatives	
Total	$ (232.1)		$ 58.0		$ 13.7

Revised (2)

Derivatives cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCL on Derivative (Effective portion)	Location of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Location of Gain (loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain (Loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
Commodity - Oil	$ (219.3)	Sales of oil and gas	$ 53.9	Sales of oil and gas	$
Commodity - Natural Gas	12.9	Sales of oil and gas	25.4	Gain (loss) on derivatives	(0.6)
Interest rate	(2.7)	Interest expense	(7.0)	Gain (loss) on derivatives	
Total	$ (209.1)		$ 72.3		$ (0.6)

(1) Revised amounts are reflected in the Statement of Comprehensive Income (Loss) for the year ended December 31, 2009 within this Form 10-K/A.

(2) Revised amounts are reflected in Note 3 to the financial statements within this Form 10-K/A.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Financial Statements and Schedules

See Item 8 Index to Financial Statements and Supplementary Data in this Form 10-K/A.

B. Exhibits

Exhibit No.	Description of Exhibit
3.1*	Registrant s Amended and Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Registrant s Quarterly Report on Form 10-Q for the period ended June 30, 2006, File No. 1-09735).
3.2*	Registrant s Restated Bylaws dated December 11, 2009 (filed as Exhibit 3.1 to the Registrant s Current Report on Form 8-K on December 11, 2009, File No. 1-09735).
4.1*	Form of Indenture between Berry Petroleum Company and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.3 to the Registrant s Registration Statement on Form S-3ASR on June 15, 2006, File No. 1-9735).
4.2*	First Supplemental Indenture, dated as of October 24, 2006, between the Registrant and Wells Fargo Bank, National Association as Trustee relating to the Registrant s 8 1/4% Senior Subordinated Notes due 2016 (filed as Exhibit 4.1 to the Registrant s Current Report on Form 8-K on October 25, 2006 File No. 1-9735).
4.3*	Registrant s 8.25% Senior Subordinated Notes (filed as Form 425B5 on October 19, 2006).
4.4*	Registrant s Certificate of Designation, Preferences and Rights of Series B Junior Participating Preferred Stock (filed as Exhibit A to the Registrant s Registration Statement on Form 8-A12B on December 7, 1999, File No. 001-09735).
4.5*	Rights Agreement between Registrant and ChaseMellon Shareholder Services, L.L.C. dated as of December 8, 1999 (filed by the Registrant on Form 8-A12B on December 7, 1999, File No. 001-09735).
4.6*	Registrant s 10¼ % Senior Notes due 2014 (filed as Form 425B5 on August 12, 2009)
4.7*	Indenture, dated June 15, 2006,between Berry Petroleum Company and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.1 to the Registrant s Current Report on Form 8-K on May 29, 2009, File No. 1-09735)
4.8*	First Supplemental Indenture, dated May 27, 2009, between Berry Petroleum Company and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.2 to the Registrant s Current Report on Form 8-K on May 29, 2009, File No. 1-09735)
4.9*	Form of 10 ¼% Senior Notes due 2014 (Included in Exhibit 4.2 to the Registrant s Current Report on Form 8-K on May 29, 2009, File No. 1-09735)
10.1*	Instrument for Settlement of Claims and Mutual Release by and among Registrant, Victory Oil Company, the Crail Fund and Victory Holding Company effective October 31, 1986 (filed as Exhibit 10.13 to Amendment No. 1 to the Registrant s Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240).
10.2*	Description of Short-Term Cash Incentive Plan of Registrant (filed as Exhibit 10.1 to the Registrant s Annual Report on Form 10-K for the period ended December 31, 2006, File No. 1-9735).
10.3*	Form of Change in Control Severance Protection Agreement dated August 24, 2006, by and between Registrant and selected employees of the Company (filed as Exhibit 99.1 to the Registrant s Current Report on Form 8-K on August 24, 2006, File No. 1-9735).
10.4*	Amended and Restated 1994 Stock Option Plan (filed as Exhibit 4.1 to the Registrant s Registration Statement on Form S-8 filed on August 20, 2002, File No. 333-98379).

10.5*	First Amendment to the Registrant s Amended and Restated 1994 Stock Option Plan dated as of June 23, 2006 (filed as Exhibit 99.3 to the Registrant s Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.6*	Berry Petroleum Company 2005 Equity Incentive Plan (filed as Exhibit 4.2 to the Registrant s Form S-8 filed on July 29, 2005, File No. 333-127018).
10.7*	Form of the Stock Option Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 4.3 to the Registrant s Form S-8 filed on July 29, 2005, File No. 333-127018).
10.8*	Form of the Stock Appreciation Rights Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 4.4 to the Registrant s Form S-8 filed on July 29, 2005, File No. 333-127018).
10.9*	Form of Stock Award Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 99.4 to the Registrant s Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.10*	Form of Restricted Stock Award Agreement, by and between Registrant and selected directors (filed as Exhibit 99.1 on Form 8-K filed on December 17, 2007, File No. 1-9735).
10.11*	Form of Restricted Stock Award Agreement, by and between Registrant and selected officers (filed as

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	Exhibit 99.2on Form 8-K December 17, 2007, File No. 1-9735).
10.12	Non-Employee Director Deferred Stock and Compensation Plan (as amended and restated effective November 19, 2008).
10.13*	Amended and Restated Employment Contract dated as of June 23, 2006 by and between the Registrant and Robert F. Heinemann (filed as Exhibit 99.1 to the Registrant s Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.14*	Stock Award Agreement dated as of June 23, 2006 by and between the Registrant and Robert F. Heinemann (filed as Exhibit 99.2 to the Registrant s Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.15*	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and David D. Wolf (Filed as Exhibit 10.1 in Registrant s Form 8-K/A filed on November 21, 2008, File No. 1-9735)
10.16*	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and Michael Duginski (filed as Exhibit 10.1 in Registrant s Form 8-K filed on November 21, 2008, File No. 1-9735)
10.17*	Amended and Restated Credit Agreement, dated as of July 15, 2008, by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions (filed as Exhibit 10.1 to the Registrant s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2008, File No. 1-9735).
10.18*	Credit Agreement by and among Berry Petroleum Company, Societe Generale, SG Americas Securities, LLC, BNP Paribas Securities Corp., BNP Paribas, and other financial institutions dated July 31, 2008 (filed as Exhibit 10.2 on Form 10-Q for the period ended September 30, 2008, File No. 1-09735).
10.19*	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 (filed on October 17, 2008, as Exhibit 10.1 to the Registrant s Current Report on Form 8-K File No. 1-9735).
10.20*	Joinder Agreement dated November 13, 2008 by and among Berry Petroleum Company, Wells Fargo Bank, N.A., and Bank of Montreal (filed as Exhibit 10.1in Registrant s Form 8-K filed on November 17, 2008, File No. 1-9735).
10.22*	Crude oil purchase contract, dated November 14, 2005 between Registrant and Big West of California, LLC (filed as Exhibit 99.2 on Form 8-K filed on November 22, 2005, File No. 1-9735).
10.21*	Joinder Agreement dated December 2, 2008 by and among Berry Petroleum Company, Wells Fargo Bank, N.A., and Calyon New York Branch (filed as Exhibit 10.1in Registrant s Form 8-K filed on December 4, 2008, File No. 1-9735).
10.23* **	Carry and Earning Agreement, dated June 7, 2006, between Registrant and EnCana Oil & Gas (USA), Inc. (filed as Exhibit 99.2 on Form 8-K on June 19, 2006, File No. 1-9735).
10.24* **	Crude Oil Supply Agreement between the Registrant and Holly Refining and Marketing Company - Woods Cross (filed as Exhibit 10.22 to the Registrant s Annual Report on Form 10-K for the period ended December 31,2006, File No. 1-0735).
10.25*	Purchase and Sale Agreement Between O Brien Resources, LLC, Sepco II, LLC, Liberty Energy, LLC, Crow Horizons Company and O Benco II LP collectively as Seller and Berry Petroleum Company as Purchaser, dated as of June 10, 2008 (filed as Exhibit 10.2 to the Registrant s Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 1-9735).
10.26*	Overriding Royalty Purchase Agreement between O Brien Resources, LLC, as Seller and Berry Petroleum Company as Purchaser, dated as of June 10, 2008 (filed as Exhibit 10.3 to the Registrant s Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 1-9735).
10.27*	Second Amendment to the Amended and Restated Credit Agreement, dated as of February 19, 2009 (filed as Exhibit 10.1 to the Registrant s Current Report on Form 8-K on February 20, 2009, File No. 1-9735).
10.28 * **	Crude Oil Purchase Contract dated March 20, 2009, between the Registrant and Tesoro Corporation (filed as Exhibit 10.1 to the Registrant s Quarterly Report on Form 10-Q for the period ended March 31, 2009, File No. 1-09735)
10.29*	Third Amendment to Amended and Restated Credit Agreement dated April 27, 2009 by and among Registrant, Wells Fargo Bank National Association, individually and as administrative agent, and certain financial institutions, as lenders (filed as Exhibit 10.2 to the Registrant s Quarterly Report on Form 10- for the period ended March 31, 2009, File No. 1-09735)
10.30*	Second Lien Credit Agreement date April 27, 2009, among Registrant, Wells Fargo Energy Capital, Inc., as administrative agent, and certain financial institutions, as Lenders and agents (Filed as Exhibit 10.3 to the Registrant s Quarterly Report on Form 10- for the period ended March 31, 2009, File No. 1-09735)
10.31*	Underwriting Agreement, dated May 21, 2009, by and between Registrant and Wachovia Capital Markets, LLC, RBS Securities Inc., BNP Paribas Securities Corp., SG Americas Securities, LLC and Calyon Securities (USA) Inc., (filed as Exhibit 1.1 to the Registrant s Current Report on Form 8-K on May 27, 2009, File No. 1-9735).
10.32*	Underwriting Agreement, dated August 11, 2009, by and among Registrant and Wachovia Capital Markets, LLC, RBS Securities Inc., BNP Paribas Securities Corp., SG Americas Securities, LLC and Calyon Securities (USA) Inc., as representatives of the underwriters named therein (filed as Exhibit 1.1 to the Registrant s Current Report on Form 8-K on August 13, 2009, File No. 1-9735).

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10.33* **	Crude Oil Purchase Contract dated September 24, 2009 between the Registrant and ExxonMobil Oil Corporation (filed as Exhibit 10.2 to the Registrant s Quarterly Report on Form 10-Q for the period ended September 30, 2009, File No. 1-9735).
10.34*	Underwriting Agreement dated January 14, 2010 by and between Registrant and the several Underwriters listed in Schedule 1 thereto (filed as Exhibit 1.1 to the Registrant s Current Report on Form 8-K on January 19, 2010, File No. 1-9735).
12.1	Ratio of Earnings to Fixed Charges.
23.1	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
23.2	Consent of DeGolyer and MacNaughton.
31.1	Certification of Chief Executive Officer pursuant to SEC Rule 13(a)-14(a).
31.2	Certification of Chief Financial Officer pursuant to SEC Rule 13(a)-14(a).
32.1	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code.
32.2	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code.
99.1*	Form of Indemnity Agreement of Registrant (filed as Exhibit 99.1 in Registrant s Annual Report on Form 10-K filed on March 31, 2005, File No. 1-9735).
99.2*	Form of B Group Trust (filed as Exhibit 28.3 to Amendment No. 1 to Registrant s Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240).
99.3	Report of DeGolyer and MacNaughton dated February 19, 2010 regarding Registrant s reserves estimates.

* Incorporated by reference

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

Previously filed as an exhibit to the original Form 10-K filed on February 25, 2010

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Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on August 11, 2010.

BERRY PETROLEUM COMPANY

By:/s/ Jamie L. Wheat
JAMIE L. WHEAT
Controller
(Principal Accounting Officer)