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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended **December 31, 2010**

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 ☒ 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 ☒

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 ☒ 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 ☒ 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 ☒ 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 ☒

As of June 30, 2010, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $1,164,242,806.

As of February 11, 2011, the registrant had 51,434,804 shares of Class A Common Stock outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on February 11, 2011, all of which are held by an affiliate of the registrant.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its Annual Meeting of Shareholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

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Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Annual Report on Form 10-K that are not historical facts are forward-looking statements that involve risks and uncertainties. Words or forms of words such as "will," "might," "intend," "continue," "target," "expect," "achieve," "strategy," "future," "may," "could," "goal," "forecast," "anticipate," "estimate," or other comparable words or phrases, or the negative of those words, and other words of similar meaning, indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A. in this Annual Report on Form 10-K, under the heading "Risk Factors."

PART I

Item 1. Business

General

We are an independent energy company engaged in the production, development, exploitation and acquisition of crude oil and natural gas. We were incorporated in Delaware in 1985 and have been a publicly traded company since 1987. We can trace our roots in California oil production back to 1909. Since 2002, we have expanded our portfolio of assets through selective acquisitions driven by a consistent focus on properties with proved reserves and significant growth potential through low risk development. Our principal reserves and producing properties are located in California, Texas (E. Texas and the Permian), Utah (Uinta) and Colorado (Piceance).

We operate in one industry segment, which is the production, development, exploitation and acquisition of crude oil and natural gas, and all of our operations are conducted in the United States. Consequently, we currently report a single industry segment. See Item 8. Financial Statements and Supplementary Data for financial information about this industry segment. Information contained in this Annual Report on Form 10-K reflects our business during the year ended December 31, 2010 unless noted otherwise.

Restatement of Previously Issued Financial Statements

In 2009, we sold all of our interest in our properties located in the Denver-Julesburg basin (DJ). At the time of the DJ asset sale, we had designated derivative instruments as cash flow hedges from the forecasted sale of natural gas produced by the DJ assets. We determined that as a result of the sale of the DJ assets, the forecasted transactions were no longer probable of occurring. Accordingly, we discontinued hedge accounting for those hedges and the accumulated amount within Accumulated other comprehensive loss related to those derivatives was included in earnings from continuing operations. In addition, all recurring income statement impacts from the derivatives designated as hedges of future production expected from the DJ assets were classified as continuing operations. We had previously classified the realized gains on derivative instruments designated as cash flow hedges from the forecasted sales of natural gas produced by the DJ assets as part of continuing operations on the basis that our hedging program was managed for the purposes of corporate risk management and that hedge gains and losses were not indicative of individual asset performance when determining the amounts to include in discontinued operations.

However, after discussions with the staff of the Securities and Exchange Commission (SEC), we determined that such gains should have been classified as part of discontinued operations, on the basis that these hedges were documented as relating to the DJ assets to achieve cash flow hedge accounting in accordance with authoritative literature.

The effect of correcting the classification of these gains resulted in a decrease in earnings from continuing operations of $12.7 million ($0.28 per diluted share) and $1.2 million ($0.02 per diluted share) for 2009 and 2008, respectively, with a corresponding increase in earnings and earnings per diluted share from discontinued operations, net of income taxes, for the same periods. The change in classification did not affect net earnings for 2009, 2008, or any of our previously issued financial statements, nor did it have an impact on any of our previously issued Balance Sheets, Statements of Shareholders' Equity or Statements of Cash Flows. See Note 16 to the Financial Statements.

Business Strengths

Balanced High Quality Asset Portfolio. Since 2002, we have grown our asset base and diversified our California heavy oil assets through acquisitions in the Permian, Uinta, E. Texas and Piceance that have significant growth potential. Our diverse asset base provides us with the flexibility to reallocate capital among our assets depending on fluctuations in oil and natural gas prices as well as area economics.

Long-Lived Proved Reserves with Stable Production Characteristics. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics, with a ratio of proved reserves to production of approximately 23 years.

Low-Risk Multi-Year Drilling Inventory in Established Resource Plays. Most of our drilling locations are located in proven resource plays that possess low geologic risk, leading to predictable drilling results. We have a significant inventory of primary development locations as well as heavy oil thermal opportunities.

Operational Control and Financial Flexibility. We exercise operating control over more than 97% of our assets. We generally prefer to retain operating control over our properties, allowing us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production, and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary which allows us a significant degree of flexibility to adjust the size of our capital budget. We finance our drilling budget primarily through our internally generated operating cash flows.

Experienced Management and Operational Teams. Our core team of technical staff and operating managers has broad industry experience, including experience in heavy oil thermal recovery operations and unconventional reservoir development and completion. We continue to utilize technologies and steam practices that will allow us to improve the ultimate recoveries of crude oil on our California properties.

Corporate Strategy

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

Maximize Production from Our Base Oil Assets. We are focused on the timely and prudent development of our large oil resource base through developmental and step-out drilling, down-spacing, well completions, remedial work and by application of enhanced oil recovery (EOR) methods and optimization technologies, as applicable.

Grow Oil Production from Our Inventory of Organic Development Projects. We have a proven track record of developing reserves through enhanced recovery projects and maximizing the efficiency of repeatable development projects. We plan to continue our focus on low-risk development of our existing assets rather than exploration.

Meet the Growing Demand for Steam Generation. We expect our enhanced oil development projects will require increasing quantities of natural gas for steam generation. Our E. Texas, Piceance, Uinta and Permian assets produce natural gas that offsets our consumption of natural gas utilized to generate steam used in our EOR activities.

Invest our Capital in a Disciplined Manner and Maintain a Strong Financial Position. We focus on utilizing our available capital on projects where we are likely to have success in increasing production and reserves at attractive returns. We believe that maintaining a strong financial position will allow us to capitalize on investment opportunities in all commodity cycles. Our capital programs are generally developed to be fully funded through internally generated cash flows. We hedge a portion of our production and utilize long-term sales contracts to maintain a strong financial position and provide the cash flow necessary for the development of our assets.

Acquire Additional Resources with an Emphasis on Crude Oil. We have been successful in expanding operations through targeted acquisitions that meet our economic criteria with a primary focus on large repeatable oil development potential. We target acquisitions in and around our existing core areas and evaluate new core areas if assets become available that complement our existing portfolio. We will also continue to evaluate and make opportunistic acquisitions of natural gas properties that can be developed at reasonable costs.

Acquisition and Divestiture Activities

The following sets forth our significant acquisitions and divestures over the last several years:

2010 Acquisitions. In 2010, we made multiple acquisitions, each of which involved interests in properties located primarily in the Permian, for approximately $334 million.

2009 Divestitures. In 2009, we sold all of our interest in our DJ assets for approximately $140 million.

2008 Acquisitions. In 2008, we acquired interests in producing properties in Limestone and Harrison counties in E. Texas for approximately $668 million.

Properties

The following table provides information regarding our operations by area as of December 31, 2010:

Name, State	Total Net Acres	Proved Reserves (MMBOE)(1)	Proved Developed Reserves (MMBOE)	Proved Undeveloped Reserves (MMBOE)	2010 Gross Wells(2)	2010 Net Wells(2)
S. Midway, CA	3,062	57.8	47.9	9.9	59	58
N. Midway, CA	3,561	59.5	28.3	31.2	71	71
Permian, TX	19,791	33.8	4.5	29.3	26	24
Uinta, UT	107,245(3)	24.3	12.2	12.1	60	58
E. Texas	4,777	40.5	28.0	12.5	8	8
Piceance, CO	8,124	55.3	12.8	42.5	17	13
Totals	146,560	271.2	133.7	137.5	241	232

(1) MMBOE—Million BOEs.

(2) Gross and net productive wells drilled during 2010.

(3) Does not include an additional 61,230 net acres that are subject to drill-to-earn agreements. Includes 7,790 net acres in Nevada.

We currently have six asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including Diatomite (N. Midway), Permian, Uinta, E. Texas and Piceance.

S. Midway—We own and operate properties in the South Midway-Sunset Field in the San Joaquin Valley. Production from our properties in the South Midway-Sunset Field relies on thermal EOR methods, primarily cyclic steaming, to place steam effectively into the remaining oil column. This is our most mature thermally enhanced asset, with production from our Ethel D properties having commenced 100 years ago. In 2009, we drilled 19 horizontal wells and 18 vertical producers at the South Midway-Sunset Field. We also accelerated our continuous steam support for these horizontal wells by drilling six vertical steam injectors. In 2010, we expanded cyclic development and drilled 35 new producers, increasing production by 500 BOE/D from 2009. At Homebase and Formax, we continued our horizontal drilling program and expanded the continuous steam injection project by drilling 15 horizontal wells and 10 vertical steam injectors. In 2011, we expect to drill an additional four horizontal wells and 13 vertical injectors at Homebase and Formax. At Ethel D, our steam flood pilot was deemed economic and, as a result, we plan to drill 15 vertical producers and eight steam injectors in 2011.

In 2003, we acquired the Poso Creek properties in the San Joaquin Valley and have proceeded with a successful thermal EOR redevelopment. Average production from these properties increased from 50 BOE/D at acquisition in 2003 to 3,400 BOE/D in 2010. In 2010, we expanded the steam flood by drilling nine new producers and three new injectors. We also commissioned a new water plant to accommodate future production growth. In 2011, we will continue to expand the steam flood at Poso Creek by drilling nine producers and three steam flood injectors.

Average daily production from all S. Midway assets was approximately 11,780 BOE/D in 2010 compared to 11,430 BOE/D in 2009.

N. Midway—Our N. Midway assets include Diatomite, Placerita and McKittrick. During 2009, we drilled 51 Diatomite wells and installed additional steam generation and water treating facilities. Average production in 2009 was 3,100 BOE/D. Diatomite production in 2010 averaged 2,720 BOE/D and was impacted by a suspension of drilling activity as we worked to secure permits from the California Division of Oil, Gas and Geothermal Resources (DOGGR) and conducted field optimization activities prior to resuming. Steam injection, which had been averaging over 30,000 barrels of steam per day (BSPD) earlier in the year, decreased as a result of the facility and infrastructure modifications. In September 2010, we received approval from the DOGGR for the next phase of development of our Diatomite project, and full project approval appears to be on schedule. The first rig resumed drilling in early October 2010, and a second rig was added in December 2010. Steam injection has steadily increased, and we exited 2010 at approximately 31,500 BSPD. Production from our Diatomite asset is expected to increase to 5,000 BOE/D by mid-2011 as we continue our development program and continue to increase steam injection. At McKittrick 21Z, we evaluated the performance of cyclic steam operations and found them to be economic. As a result, we plan to drill 44 McKittrick wells and expand infrastructure in 2011. We intend to focus additional capital investment in 2011 on initiating steam flood pilots at our Fairfield, Pan, USL-12, and Main Camp properties located in N. Midway. Average daily production from all N. Midway assets was approximately 5,320 BOE/D in 2010 compared to 5,480 BOE/D in 2009.

Permian—In 2010, we acquired 19,791 net acres in the Wolfberry trend. We have identified over 400 drilling locations on 40-acre spacing and an additional 400 locations on 20-acre spacing. In 2010, we drilled 26 gross (24 net) wells, with 21 gross (19 net) wells coming in the second half of 2010 when we executed a three rig drilling program. In 2011, we plan to average a four rig program and drill approximately 72 gross wells. We exited 2010 at approximately 2,550 BOE/D.

Uinta—In 2003, we established our initial acreage position in the Uinta, which includes the Ashley Forest area, targeting the Green River formation that produces both light oil and natural gas. We acquired the Brundage Canyon leasehold in Duchesne County in Northeastern Utah, which consists of working interests in approximately 51,000 gross acres on federal, tribal, and private leases. We have working interests in approximately 57,000 gross acres and exploratory rights in approximately 61,230 net acres in the Lake Canyon project, which is located immediately west of our Brundage Canyon producing properties. In 2010 we drilled 60 gross (58 net) wells, which included 36 gross (35 net) wells in Brundage Canyon, 20 gross (20 net) wells in Ashley Forest and four gross (three net) wells in Lake Canyon. We also participated in four non-operated Lake Canyon wells. The Lake Canyon drilling program identified a new pay interval in the Upper Wasatch that was commingled with the Green River formation, yielding encouraging results. We continue to monitor the progress of our initial water flood pilot in Brundage Canyon, which was implemented in the fourth quarter of 2009, and began injection on our second Brundage Canyon water flood pilot in the fourth quarter of 2010. The Ashley Forest Environmental Impact Study (EIS) continues to progress, and we anticipate approval in 2011. We plan to run a one rig program in the Uinta in 2011 focused toward developing areas of higher oil potential with added emphasis on the development of Lake Canyon. Our drilling inventory in the Uinta is approximately 350 locations distributed between Brundage Canyon, Ashley Forest, and Lake Canyon. Average daily production in Uinta was approximately 5,350 BOE/D in 2010 compared to 4,930 BOE/D in 2009.

E. Texas—In 2008, we acquired certain interests in natural gas producing properties on approximately 4,500 net acres in Limestone and Harrison Counties in E. Texas. The Limestone County assets include seven productive horizons in the Cotton Valley and Bossier sands at depths between 8,000 and 13,000 feet. Additional potential exists in the Haynesville/Bossier shale. The Harrison County assets include five productive sands as well as the Haynesville/Bossier Shale, with average depths between 6,500 and 13,000 feet. We recently completed an eight well Haynesville horizontal development program. We have deferred drilling in E. Texas during 2011 while we focus on higher return oil development opportunities at our other properties. Average daily production from the E. Texas assets averaged 31 MMcf/D in 2010 as compared to 24 MMcf/D in 2009.

Piceance—In 2006, we acquired two properties in the Piceance targeting the Williams Fork section of the Mesaverde formation. We have a 62.5% working interest in 6,300 gross acres on our Garden Gulch property, a working interest of 95% in 4,300 gross acres and a 5% non-operating working interest in 90 wells on our North Parachute property. We have accumulated a sizable resource base, which should allow us to add significant proved reserves as we develop these assets. We have successfully drilled 111 gross wells (69 net) at Garden Gulch and 33 gross wells (31 net) on the North Parachute property since the acquisitions of those properties. During 2009, we began a 20 well completion program testing new completion designs and saw improved well performance in line with our expectations. We continue to utilize the improved completion techniques, and results continue to meet our expectations. In January 2011, we renegotiated the agreement covering the North Parachute property such that we have until January 31, 2020 to complete our drilling obligations. See Note 10 to the Financial Statements. In 2010, we continued to develop the Garden Gulch and North Parachute properties through a one rig drilling program. Average daily production in the Piceance has increased from 4 MMcf/D in 2006 to 23 MMcf/D in 2010.

Oil and Gas Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2010 based on the unweighted arithmetic average of the first-day-of the month prices during the 12-month period prior to December 31, 2010.

	Estimated Proved Reserves		
	Oil (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Developed	88,917	268,566	133,678
Undeveloped	77,264	361,626	137,535
Total proved—December 31, 2010	166,181	630,192	271,213

At December 31, 2010, our proved undeveloped reserves were 137.5 MMBOE. At December 31, 2009, our proved undeveloped reserves were 109.8 MMBOE. During 2010, approximately 9 MMBOE or 8% of our December 31, 2009 proved undeveloped reserves were converted into proved developed reserves from the investment of approximately $111 million of drilling, completion and facilities capital. Our proved reserves in 2010 were impacted by certain regulatory and permitting delays in our Diatomite asset in Kern County, California and by the acquisition of several properties in the Permian. We invested significant infrastructure capital in the Diatomite asset even though drilling was curtailed until the fourth quarter, which reduced the conversion of proved undeveloped reserves from this asset. The Permian properties were largely undeveloped and approximately 26 MMBOE were added to the proved undeveloped reserves category due to these acquisitions. Drilling and completion activities primarily related to our California and Permian assets, along with engineering revisions, added approximately 15 MMBOE to proved undeveloped reserves, and 5 MMBOE were removed from this category due to performance and as a result of our future development plans. We intend to grow our production and cash flow over the next several years from an increase in capital spending that will facilitate a larger conversion of proved undeveloped reserves. We intend to convert the proved undeveloped reserves recorded as of December 31, 2010 to proved developed reserves within five years of the date the reserves were initially recorded.

Preparation of Reserves Estimates

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our 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 commodity prices or development and production expenses, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates. See Part I, Item 1A—"Risk Factors," for a description of some of the risks and uncertainties associated with our business and reserves.

All of our oil and natural gas reserves are located in the U.S. We engaged DeGolyer and MacNaughton (D&M) to prepare all of our proved oil and gas reserve estimates and the estimated future net revenue to be derived from our properties. D&M is an independent petroleum engineering consulting firm that has provided consulting services throughout the world for over 70 years. The independent engineers' estimates were prepared by the use of standard geological and engineering methods generally recognized by the petroleum industry. Reserve volumes and values were determined under the method prescribed by the SEC, which requires the application of the 12-month average price for oil and natural gas calculated as the un-weighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period and year-end costs. The proved reserve estimates represent our net revenue interest in our properties. When preparing our reserve estimates, the independent engineers did not independently verify the accuracy and completeness of information and data furnished by us with respect to property interests, production from such properties, current costs of operation and development, current prices for production agreements relating to current and future operations and sale of production, and various other information and data. See Exhibit 99.3—Report of DeGolyer and MacNaughton dated February 15, 2011.

Reserves are also calculated internally and compared to the reserve estimates received from D&M. When compared on a field-by-field basis, some of our internally generated estimates of net proved reserves were greater and some were less than the estimates prepared by D&M. If a variance of greater than 10% occurs at the field level, it may suggest that a difference in methodology or evaluation techniques exist between us and the independent engineers. Those differences are investigated and discussed with the independent engineers to confirm that the proper methodologies and techniques were applied in the estimated reserves for these fields. There was no material difference, in the aggregate, between our internal estimates of estimated net proved reserves and the estimates prepared by D&M.

Our senior evaluation engineer oversees the reserve estimation process. He holds a Bachelor of Science degree in Mechanical Engineering from Texas A&M University and has over thirty years of petroleum engineering experience in oil and gas exploration, production, and reserve determination. The majority of his time in the industry has been spent in reserve analysis and evaluation. He has performed economic evaluations in all of the areas in which we operate and has supervised operations in a majority of them. Our reserves are also subject to multiple levels of management review.

Production, Average Sales Prices and Production Costs

The following table reflects our production, average sales price and production cost information for the years ended December 31, 2010, 2009 and 2008:

	Net Production Volumes(1)		Average Sales Price(2)		Average Operating Cost
	Crude Oil (BOE/D)	Natural Gas (Mcf/D)	Crude Oil ($/BOE)	Natural Gas (Mcf)	$/BOE
Year Ended December 31, 2010					
Total production—Continuing operations	21,713	65,720	$ 67.61	$ 4.37	$ 15.95
Diatomite(3)	2,721	—	75.03	—	32.08
South Midway Sunset(4)	6,889	—	63.96	—	12.77
Piceance(3)	62	22,681	64.14	4.25	8.94
Year Ended December 31, 2009					
Total production—Continuing operations	19,688	57,484	50.73	3.61	14.66
Diatomite	3,093	—	57.00	—	21.98
South Midway Sunset	7,214	—	48.68	—	10.18
Piceance	43	18,981	45.56	3.35	9.05
Year Ended December 31, 2008					
Total production—Continuing operations	20,330	50,064	86.90	6.91	17.99
Diatomite	1,843	—	91.72	—	32.52
South Midway Sunset	7,790	—	85.60	—	13.88
Piceance	58	20,700	$ 68.64	$ 6.76	$ 11.78

(1) Net production represents that owned by us and produced to our interests.

(2) Excludes all effects of derivatives. Please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information regarding the effect of derivatives on our average realized price.

(3) The Piceance and Diatomite, each of which is considered a single field, contain 15% or more of our total proved reserves.

(4) Includes Homebase and Formax.

Productive Wells and Acreage

As of December 31, 2010, we had working interests in 3,568 gross (3,485 net) active producing oil wells and 437 gross (285 net) active producing gas wells.

The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2010:

	Developed Acres(1)		Undeveloped Acres(2)		Total	
	Gross(3)	Net(3)	Gross(3)	Net(3)	Gross(3)	Net(3)
California	5,955	5,930	693	693	6,648	6,623
Colorado	2,480	1,107	9,122	7,017	11,602	8,124
Nevada	680	666	7,270	7,124	7,950	7,790
Texas	7,520	6,828	21,270	17,740	28,790	24,568
Utah(4)	20,480	19,836	125,214	79,619	145,694	99,455
Wyoming	3,880	616	1,237	196	5,117	812
Kansas	—	—	62,939	61,519	62,939	61,519
Other	40	4	—	—	40	4
Total	41,035	34,987	227,745	173,908	268,780	208,895

(1) Developed acres are acres spaced or assigned to productive wells.

(2) The undeveloped acreage subject to expiration in each of the next three years is not material.

(3) Gross acres represent acres in which we have a working interest; net acres represent our aggregate working interests in the gross acres.

(4) Does not include an additional 61,230 net acres that are subject to drill-to-earn agreements.

Drilling Activity

The following table sets forth our drilling activities for the years ended December 31, 2010, 2009 and 2008:

	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development wells drilled:						
Productive	241	232	132	132	443	374
Dry(1)	—	—	2	2	—	—
Exploratory wells drilled:						
Productive	—	—	—	—	3	2
Dry(1)	1	1	—	—	6	5
Total wells drilled:						
Productive	241	232	132	132	446	376
Dry(1)(2)	1	1	2	2	6	5

(1) A dry well is a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

(2) We achieved a gross drilling success rate of 99.6%, 98.5% and 98.7% for the years ended December 31, 2010, 2009 and 2008, respectively.

As of December 31, 2010, we had 7 rigs drilling on our properties and we had 7 gross (6 net) wells in progress.

Company owned drilling rigs

We own three drilling rigs. Owning these rigs allows us to meet a portion of our drilling needs in Uinta and the Piceance. Two of these rigs are not currently drilling, and one rig is drilling in the Uinta. We continue to evaluate the ownership of these rigs as the rig market and our rig requirements change.

Marketing and Customers

We market the majority of the natural gas and oil production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to a variety of purchasers under oil and gas purchase contracts with daily, monthly, seasonal, annual or multi-year terms, all at market prices. The majority of our sales are to marketing companies or refiners. We typically sell production to a relatively small number of customers. However, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition, results of operations, or operating cash flows.

Our oil production is collected in tanks and sold via pipeline or truck. Our oil contracts are priced either on local area oil postings or are based upon the NYMEX WTI, with location or transportation differentials. A substantial portion of our oil reserves are located in California, and approximately 52% of our production is attributable to heavy crude (generally 21 degree API gravity crude oil or lower). The market price for California crude differs from the established market indices in the U.S., due principally to the higher refining costs associated with heavy crude. As of December 31, 2010, we have over 88% of our California oil production under contract with Shell Trading (US) Company and ExxonMobil Oil Corporation through March and November 2011, respectively. The remaining California production is under contract through December 2012 with a niche refiner in the Los Angeles basin.

In Utah, we are 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 Uinta black wax crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of NYMEX WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for our 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for our crude oil. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of our crude oil sales customer in Utah could impact the marketability of a portion of our Utah crude oil volumes. Gross oil production from our Uinta properties averaged approximately 3,300 Bbl/D in 2010.

Our natural gas is transported through our own and third party gathering systems and pipelines. We incur processing, gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped and the fee charged by the third-party processor or transporter. In certain instances, we enter into firm transportation agreements to provide for pipeline capacity to flow and sell a portion of our gas volumes. Our Rocky Mountain natural gas production is tied to the eastern markets in Lebanon, Ohio, while our Utah gas production is generally priced relative to a Rocky Mountain Northwest Pipeline (NWPL) or Questar index price. Our E. Texas natural gas is generally priced off the Florida Zone 1 or the Natural Gas Pipeline Co. of America-Texok zone (NGPL Texok) index. Permian natural gas prices are generally tied to the El Paso Permian index.

In our producing areas, we have firm transportation contracts on interstate and intrastate pipelines to assure the delivery of our gas to market. At the time we entered into these commitments, we estimated that our production and the production of joint interest owners that we market, would be sufficient to meet these commitments. In California, we have firm transportation contracts to assure our ability to purchase a portion of our consumed gas outside of the California markets. The following table sets forth information about material long-term firm transportation contracts for pipeline capacity, which typically require a demand charge.

Pipeline	From	To	Quantity (Avg. MMBtu/D)	Term	December 31, 2010 demand charge per MMBtu	Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$ 0.583	$ 5,968
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 2/2018	1.134(1)	74,216
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	1/2008 to 1/2018	1.094(1)	28,306
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,500	9/2003 to 4/2012	0.174	211
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,859	9/2003 to 9/2012	0.174	318
Questar Pipeline	Brundage Canyon, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.257	5,553
Enbridge Pipeline	Limestone and Harrison Counties, TX	Orange, TX	Up to 55,000	4/2009 to 3/2012	0.22	1,597
Total			112,359			$ 116,169

(1) Base cost per MMBtu is a weighted average cost.

We have signed firm transportation service agreements with El Paso Corporation for an average total of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. The project is expected to be in service in mid-2011.

Steaming Operations

Our California assets consist of heavy crude oil which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. We utilize cyclic steam and/or steam flood recovery methods on all assets.

Cogeneration Steam Supply. In pursuing our goal of being a cost-efficient heavy oil producer in California, we have consistently focused on minimizing our steam cost. We believe one of the main methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on our properties. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility, are located in S. Midway. We also own a 42 MW cogeneration facility which is located in Placerita. Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine that would otherwise be wasted, to produce steam. This increases the efficiency of the combined process and consumes less fuel than would be required to produce the steam and electricity separately.

Conventional Steam Generation. In addition to these cogeneration plants, we own 30 fully permitted conventional steam generators. The quantity of generators operated at any point in time is dependent on (i) the steam volume required for us to achieve our targeted production and (ii) the price of natural gas compared to the realized price of crude oil sold. In 2010, we added four additional steam generators for use in our ongoing development of the Diatomite. In 2009, we added one additional 5,000 BSPD generator at Poso Creek and three additional 5,000 BSPD generators on our Diatomite producing properties.

Ownership of these varied steam generation facilities and sources allows for maximum operational control over the steam supply, location, and to some extent, over the aggregated cost of steam generation. Our steam supply and flexibility are crucial for the maximization of California thermally enhanced heavy oil production, cost control and ultimate oil recovery.

Total barrels of steam per day (BSPD) capacity as of December 31, 2010 are as follows:

Steam generation capacity of conventional steam generators	113,208
Steam generation capacity of cogeneration plants	42,789
Additional steam purchased under contract with a third party	1,957
Total steam capacity	157,954

The average gross volume of steam injected for the years ended December 31, 2010 and 2009 was 116,956 BSPD and 109,153 BSPD, respectively.

During December 2010, approximately 77% of the volume of natural gas purchased to generate steam and electricity was based upon California indices. We pay distribution/transportation charges for the delivery of gas to our various locations where we consume gas for steam generation purposes. However, in some cases, this transportation cost is embedded in the price of gas. Approximately 23% of supply volume is purchased in the Rockies and moved to the Midway-Sunset field using our firm transportation capacity on the Kern River Pipeline. This gas is generally purchased based upon the NWPL index.

	2010	2009	2008
Average SoCal Border Monthly Index Price per MMBtu	$ 4.34	$ 3.59	$ 7.92
Average Rocky Mountain NWPL Monthly Index Price per MMBtu	3.94	3.09	6.25
Average PG&E Citygate Monthly Index Price per MMBtu	4.66	4.17	8.63

We are a net seller of natural gas and benefit operationally when natural gas prices increase. However, our consumption of natural gas provides a form of natural hedge as our revenues received from natural gas sales are partially offset by operating cost increases in California when natural gas prices rise. The following table shows our average 2010 and estimated average 2011 amount of production in excess of consumption and hedged volumes (in average MMBtu/D):

	2010	Estimated 2011
Approximate natural gas volumes produced in operations	65,720	70,500
Approximate natural gas consumed:		
Cogeneration operations	27,083	25,500
Conventional steam generators	27,108	40,500
Total natural gas volumes consumed in operations	54,191	66,000
Less: Our estimate of approximate natural gas volumes consumed to produce electricity(1)	(18,171)	(17,000)
Total approximate natural gas volumes consumed to produce steam	36,020	49,000
Natural gas volumes hedged	19,000	15,000
Amount of natural gas volumes produced in excess of volumes consumed to produce steam and volumes hedged	10,700	6,500

(1) We estimate this volume based on the historical allocation of fuel costs to electricity.

Electricity

Generation. The total annual average electrical generation of our three cogeneration facilities is approximately 93 MW, of which we consume approximately 8 MW for use in our operations. Each facility is centrally located on certain of our oil producing properties. Thus the steam generated by each facility is capable of being delivered to numerous wells that require steam for the EOR process. Our investment in our cogeneration facilities has been for the express purpose of lowering the steam costs in our heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam generators. Cogeneration costs are allocated between electricity generation and oil and gas operations based on the conversion efficiency (of fuel to electricity and steam) of each cogeneration facility and certain direct costs to produce steam. Cogeneration costs allocated to electricity will vary based on, among other factors, the thermal efficiency of our cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of our power contracts. Although we account for cogeneration costs as described above, economically we view any profit or loss from the generation of electricity as a decrease or increase, respectively, to our total cost of producing heavy oil in California. Depreciation, depletion and amortization (DD&A) related to our cogeneration facilities is allocated between electricity operations and oil and gas operations using a similar allocation method.

Sales Contracts. We sell electricity produced by our cogeneration facilities to two California public utilities: Southern California Edison Company (Edison) and Pacific Gas and Electric Company (PG&E), under long-term contracts approved by the California Public Utilities Commission (CPUC). These contracts are referred to as standard offer (SO) contracts under which we are paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) of energy plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. During most periods, natural gas is the marginal fuel for California utilities, so this formula provides a hedge against our cost of gas to produce electricity and steam in our cogeneration facilities. On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes the way SRAC energy prices will be determined for existing and new SO contracts and revises the capacity prices paid under current SO1 contracts. The revised pricing ordered in the SRAC Decision became effective on August 1, 2009. Certain elements of the revised pricing have not been resolved in legal and regulatory proceedings. It has not been determined whether the revised SRAC pricing will be applied retroactively, and if so, for what period. All pending legal and regulatory challenges are being held in abeyance pending final effectiveness of a global settlement approved by the CPUC in December 2010 but still subject to certain conditions precedent (Global Settlement). We do not expect the prospective reduction in electricity revenue as a result of lower SRAC prices to be material to us.

In December 2004, we executed a five-year SO1 contract with Edison for the Placerita Unit 2 facility, and five-year SO1 contracts with PG&E for the Cogen 18 and Cogen 38 facilities, each effective January 1, 2005. Our SO2 contract with Edison for the Placerita Unit 1 Facility expired on March 25, 2009. Effective upon their scheduled terminations, each of the four contracts was extended pursuant to the SRAC Decision. On December 21, 2010, we executed agreements with PG&E, which extend the electricity sales contracts for our 18 MW and 38 MW facilities until December 31, 2011. These contracts could also terminate earlier upon CPUC approval of replacement contracts, or under certain other limited circumstances. Our electricity sales contracts with Edison for our Placerita facility will continue in effect until the CPUC approves and makes available replacement SO contracts, which, under the Global Settlement, will likely be sometime in 2011; however, our current contracts could terminate earlier under certain limited circumstances. The payment provisions of the extension agreements reflect the payment provisions ordered in the SRAC Decision.

Upon Edison and PG&E's challenge in the California Court of Appeals of the legality of the CPUC decision that ordered the utilities to enter into these SO contracts, the court ruled that the

CPUC had the right to order the utilities to execute these contracts and that the CPUC was obligated to review the prices paid under the contracts and to adjust the prices retroactively to the extent it was later determined that such prices did not comply with certain requirements. A CPUC proceeding to resolve this retroactive price issue is being held in abeyance pending the outcome of the Global Settlement. We intend to enter into new SO contracts with Edison and PG&E for all of these facilities as soon as the ongoing challenges are resolved and the CPUC has approved the terms of new SO contracts. See Item 1A. Risk Factors—"The future of the electricity market in California is uncertain."

Facility and Contract Summary

Location and Facility	Type of Contract	Purchaser	Contract Expiration	Approximate Megawatts Available for Sale	Approximate Megawatts Consumed in Operations	Approximate Barrels of Steam Per Day
Placerita						
Placerita Unit 1	SO2	Edison	(1)	20	—	6,500
Placerita Unit 2	SO1	Edison	(1)	17	4	6,500
S. Midway						
Cogen 18	SO1	PG&E	Dec-11(2)	11	4	6,400
Cogen 38	SO1	PG&E	Dec-11(2)	37	—	18,000

(1) The term of this agreement was extended until the CPUC approves a replacement contract.

(2) This agreement was extended until December 31, 2011, but could terminate earlier upon CPUC approval of replacement contracts.

Competition

The oil and gas industry is highly competitive. As an independent producer, we have little control over the price we receive for our crude oil and natural gas. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to our customers. In acquisition activities, competition is intense as integrated and independent companies and individual producers are active bidders for desirable oil and gas properties and prospective acreage. Although many of these competitors have greater financial and other resources than we have, we are in a position to compete effectively due to our business strengths.

Title to Properties

Prior to the time we acquire undeveloped properties, we conduct a title investigation consistent with industry custom and practice. Most developed properties we acquire have existing title opinions. In addition, prior to commencement of drilling operations we obtain a drilling title opinion which, in the event production is achieved, is supplemented with a division order title opinion or its equivalent. To date, we have obtained or commissioned title opinions on virtually all of our producing properties and have satisfactory title to those properties in accordance with industry standards. A majority of our oil and gas properties are subject to a mortgage or deed of trust under our second amended and restated senior secured revolving credit facility (Credit Agreement), as well as to customary royalty interests, liens incidental to operating agreements, tax liens, and other minor burdens, encumbrances, easements and restrictions which do not materially interfere with the use of or affect the value of such properties.

Employees

As of December 31, 2010, we had 270 full-time employees. We also contract for the services of independent consultants involved with land, regulatory, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by a collective bargaining agreement. Our relations with our employees are good.

Offices

Our corporate headquarters are located in Denver, Colorado, and we have regional offices in Bakersfield, California, Plano, Texas and Midland, Texas.

Available Information

Our website, located at http://www.bry.com, can be used to access recent news releases and Securities and Exchange Commission (SEC) filings, crude oil price postings, hedging summaries, our Annual Report, Proxy Statement, Board committee charters, Corporate Governance Guidelines, code of business conduct and ethics, the code of ethics for senior financial officers, and other items of interest. Information on our website is not incorporated into this report. SEC filings, including supplemental schedules and exhibits, can also be accessed free of charge through the SEC website at http://www.sec.gov.

Environmental and Other Regulations

We are committed to responsible management of the environment and prudent health and safety policies, as these areas relate to our operations. We strive to achieve the long-term goal of sustainable development within the framework of sound environmental, health and safety practices and standards. We strive to make environmental, health and safety protection an integral part of all business activities, from the acquisition and management of our resources to the decommissioning and reclamation of our wells and facilities.

We have programs in place to identify and manage known risks, to train employees in the proper performance of their duties and to incorporate viable new technologies into our operations. The costs incurred to ensure compliance with environmental, health and safety laws and other regulations are normal operating expenses and are not material to our operating costs. There can be no assurances, however, that changes in, or additions to, laws and regulations regarding the protection of the environment will not have an impact in the future. We maintain insurance coverage that is customary in the industry although we are not fully insured against all environmental or other risks.

Environmental Regulation. Our oil and gas exploration, production and related operations are subject to numerous and frequently changing federal, state, tribal and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Environmental laws and regulations may require the acquisition of certain permits prior to or in connection with activities or other operations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment including releases in connection with drilling and production, restrict or prohibit drilling activities or other operations that could impact wetlands, endangered or threatened species or other protected areas or natural resources, require remedial action to mitigate pollution from ongoing or former operations, such as cleanup of environmental contamination, pit cleanups and plugging of abandoned wells, and impose substantial liabilities for pollution resulting from our operations. See Item 1A Risk Factors—"We are subject to existing and pending laws and regulations that could give rise to substantial liabilities from environmental contamination or otherwise adversely affect our cost, manner or feasibility of doing business."

Regulation of Oil and Gas. The oil and gas industry, including our operations, is extensively regulated by numerous federal, state and local authorities and, with respect to tribal lands, Native American tribes. These types of regulations include requiring permits for the drilling of wells, the posting of drilling bonds and the reports concerning operations. Regulations may also govern the location of wells, the method of drilling and casing wells, the rates of production or "allowables," the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the notifying of surface owners and other third parties. Certain laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. We are also subject to various laws and regulations pertaining to Native American tribal surface ownership, to Native American oil and gas leases and other exploration agreements, fees, taxes, or other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations.

Federal Energy Regulation. The enactment of the Public Utilities Regulatory Policy Act, 1978 (PURPA), as amended, and the adoption of regulations there under by the Federal Energy Regulatory Commission (FERC) provided incentives for the development of cogeneration facilities such as ours. A domestic electricity generating project must be a Qualifying Facility (QF) under FERC regulations in order to benefit from certain rate and regulatory incentives provided by PURPA.

PURPA provides two primary benefits to QFs. First, QFs generally are relieved of compliance with extensive federal and state regulations that control the financial structure of an electricity generating plant and the prices and terms on which electricity may be sold by the plant. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost and that the utility sell back-up power to the QF on a non-discriminatory basis. The term "avoided cost" is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. The Energy Policy Act of 2005 amended PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if FERC determines that a competitive wholesale electricity market is available to QFs in the service territory. While such a determination has not been made for our service areas in California, as part of the Global Settlement, the utilities will be relieved from this obligation precedent to the global settlement. Under the Global Settlement, the utilities will be obligated to continue offering SO contracts to QFs such as us. This amendment does not affect any of our current SO contracts.

State Energy Regulation. The CPUC has broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in California and to promulgate regulation for implementation of PURPA. Since a power sales agreement becomes a part of a utility's cost structure (generally reflected in its retail rates), power sales agreements with independent electricity producers, such as us, are potentially under the regulatory purview of the CPUC and in particular the process by which the utility has entered into the power sales agreements. While we are not subject to regulation by the CPUC, the CPUC's implementation of PURPA is important to us, as is other regulatory oversight provided by the CPUC to the electricity market in California.

Item 1A. Risk Factors

Other Factors Affecting Our Business and Financial Results

Oil and natural gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business, financial condition, results of operations and operating cash flow. Our revenues, profitability and future growth and reserve calculations depend substantially on the price received for our oil and natural gas production. These prices also affect the amount of our cash flow available for capital expenditures, working capital, payments on our various debt instruments, dividends paid on our capital stock and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can produce economically. The oil and natural gas markets fluctuate widely, and we cannot predict future oil and natural gas prices. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- regional, domestic and foreign supply and perceptions of supply of and demand for oil and natural gas;
- level of consumer demand;
- weather conditions;
- overall domestic and global political and economic conditions;
- technological advances affecting energy consumption and supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the capacity, cost and availability of oil and natural gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

Our revenue, profitability and cash flow depend upon the prices and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

- reduce the amount of cash flow available to make capital expenditures or make acquisitions;
- reduce the number of our drilling locations;
- increase the likelihood of refinery defaults;
- negatively impact the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically; and
- limit our ability to borrow money or raise additional capital.

Our heavy crude oil in California may be less economic than lighter crude oil. As of December 31, 2010, approximately 43% of our proved reserves, or 117.3 million barrels, consisted of heavy oil, and light crude oil represented 18% of our proved reserves. Heavy crude oil historically sells for a discount to light crude oil, as more complex refining equipment is required to convert heavy oil into high value products. Additionally, most of our crude oil in California is produced using steam injection. This process is generally more costly than primary and secondary recovery methods.

Purchasers of our crude oil and natural gas may become insolvent. We have significant concentrations of credit risk with the purchasers of our crude oil and natural gas. For example, all of our crude oil in Utah is sold under a long-term contract to a single refiner. Under the standard credit terms with our refiners, we may not know that a refiner will be unable to make payment to us until 50 days of our production has been delivered to them. If our purchasers become insolvent, we may not be able to collect any of the amounts owed to us. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of our crude oil sales customer in Utah could impact the marketability of a portion of our Utah crude oil volumes.

Our financial counterparties may be unable to satisfy their obligations. We rely on financial institutions to fund their obligations under our Credit Agreement and make payments to us under our hedging agreements. If one or more of our financial counterparties becomes insolvent, they may not be able to meet their commitment to fund future borrowings under our credit facility which would reduce our liquidity. Additionally, at current commodity prices, a portion of our cash flow over the next three years will come from payments from our counterparties on our commodity hedging contracts. If our counterparties are not able to make these payments, our cash flow will be reduced. Recently adopted financial reform legislation may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

A widening of commodity differentials may adversely impact our revenues and our economics. Our crude oil and natural gas are priced in the local markets where the production occurs based on local or regional supply and demand factors. The prices that we receive for our crude oil and natural gas production are generally lower than the relevant benchmark prices, such as NYMEX or Brent, that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential. We may not be able to accurately predict crude oil and natural gas differentials.

Price differentials may widen in the future. Numerous factors may influence local pricing, such as refinery capacity, pipeline takeaway capacity and specifications, localized storage capacity, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be adversely impacted by a widening differential on the products we sell. Our oil and natural gas hedges are generally based on West Texas intermediate (WTI) or natural gas index prices, so we may be subject to basis risk if the differential on the products we sell widens from those benchmarks and we do not have a contract tied to those benchmarks. Additionally, regional capacity and storage issues may cause benchmark prices to become disconnected from other sources of global crude oil and natural gas which may adversely affect the effectiveness of our hedges that are based on such indices. Insufficient pipeline capacity, storage capacity or trucking capability and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and natural gas producing areas. Increases in the differential between benchmark prices for oil and natural gas and the wellhead price we receive could adversely affect our financial condition, results of operation, and operating cash flows.

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

We may not be able to deliver minimum crude oil volumes required by our sales contract. Production volumes from our Uinta properties over the next several years are uncertain and there is no assurance that we will be able to consistently meet the minimum required volume under our refining contract relating to our production from these properties. During the term of the contract, the minimum number of delivered barrels is 5,000 BOE/D. In the event that we cannot produce the necessary volume, we may need to purchase crude to meet our contract requirements. Gross oil production from our Uinta properties averaged approximately 3,300 BOE/D during 2010.

We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. We are dependent on several cogeneration facilities that, combined, provide approximately 27% of our steam capacity as of December 31, 2010. These facilities are dependent on reasonable contracts for the sale of electricity. If, for any reason, including if utilities that purchase electricity from us are no longer required by regulation to enter into electricity sales contracts with us, we were unable to enter into new or replacement contracts or were to lose any existing contract, we may not be able to supply 100% of the steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements and availability of equipment. The financial cost and timing of such new investment may adversely affect our production, capital outlays and cash provided by operating activities. We executed agreements with Pacific Gas and Electric Company (PG&E), which extend the electricity sales contracts for our 18 MW and 38 MW facilities until December 31, 2011. These contracts could also terminate earlier upon CPUC approval of replacement contracts, or under certain other limited circumstances. Our electricity sales contracts with Southern California Edison Company (Edison) for our Placerita facility will continue in effect until the CPUC approves and makes available replacement standard form QF contracts, which, under the pending Global Settlement, will likely be sometime in 2011; however, our current contracts could terminate earlier under certain limited circumstances.

The future of the electricity market in California is uncertain. We utilize cogeneration plants in California to generate lower cost steam compared to conventional steam generation methods. Electricity produced by our cogeneration plants is sold to utilities and the steam costs are allocated to our oil and natural gas operations. We executed agreements with PG&E, which extend the electricity sales contracts for our 18 MW and 38 MW facilities until December 31, 2011. These contracts could also terminate earlier upon CPUC approval of replacement contracts, or under certain other limited circumstances. Our electricity sales contracts with Edison for our Placerita facility will continue in effect until the CPUC approves and makes available replacement standard form QF contracts, which, under the pending Global Settlement, will likely be sometime in 2011; however, our current contracts could terminate earlier under certain limited circumstances. Additionally, legal and regulatory decisions (especially related to the pricing of electricity under the contracts such as the SRAC Decision and the pending issues as to effective dates on retroactivity), can by reducing our electricity revenues adversely affect the economics of our cogeneration facilities and as a result the cost of steam for use in our oil and natural gas operations. In addition, any final determination by the CPUC to apply the SRAC pricing formula, which became effective on August 1, 2009 retroactively, so as to require payment on a one-time basis, could have a material adverse effect on our financial condition, results of operations, and operating cash flows. During the California energy crisis in 2000 and 2001, we had electricity sales contracts with PG&E and Edison, and a portion of the electricity prices paid to us under such contracts from December 2000 to March 27, 2001 has been under a degree of legal challenge since that time. 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 us. It is possible that we may have a liability pending the final outcome of the CPUC proceedings on the matter. 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. On December 21, 2010, the CPUC issued an order that approves a Global Settlement by and between the three California utilities, two consumer representative groups and three parties that represent the interests of the majority of the cogeneration facilities in the state, including us, which upon its effectiveness would extinguish all pending claims of retroactive payment liability, would make available long-term standard form QF contracts and would prospectively revise SRAC pricing. Before this Global Settlement can become effective however, it must survive certain regulatory and/or legal challenges, and the FERC must grant a forthcoming application by the California utilities to be relieved from the PURPA obligation.

A shortage of natural gas in California could adversely affect our business. We may be subject to the risks associated with a shortage of natural gas and/or the transportation of natural gas into and within

California. We are highly dependent on sufficient volumes of natural gas necessary to use for fuel in generating steam in our heavy oil operations in California. If the required volume of natural gas for use in our operations were to be unavailable or too highly priced to produce heavy oil economically, our production could be adversely impacted. We have firm transportation to move 12,000 MMBtu/D on the Kern River Pipeline from the Rocky Mountains to Kern County, CA, which accounts for approximately one-quarter of our current requirement.

Our use of oil and natural gas price and interest rate derivative contracts involves credit risk and may limit future revenues from price increases or reduced expenses from lower interest rates, as well as result in significant fluctuations in net income and shareholders' equity. We use derivative instruments with respect to a portion of our oil and natural gas production with the objective of achieving a more predictable cash flow, and reducing our exposure to a significant decline in the price of crude oil and natural gas. From time to time we utilize interest rate derivative contracts to fix the rate on a portion of our variable rate indebtedness, as only a portion of our total indebtedness has a fixed rate and we are therefore exposed to fluctuations in interest rates. While the use of derivative instruments limits the downside risk of price declines or rising interest rates, as applicable, their use may also limit future revenues from price increases or reduced expenses from lower interest rates, as applicable. Derivative transactions also involve the risk that the counterparty may be unable to satisfy its obligations.

Our future success depends on our ability to find, develop and acquire oil and natural gas reserves. To maintain production levels, we must locate and develop or acquire new oil and natural gas reserves to replace those depleted by production. Without successful exploration, exploitation or acquisition activities, our reserves, production and revenues will decline. We may not be able to find, develop or acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and natural gas prices or operating difficulties result in our cash flow from operations being less than expected or limit our ability to borrow under credit arrangements, we may be unable to expend the capital necessary to locate and to develop or acquire new oil and natural gas reserves.

Actual quantities of recoverable oil and natural gas reserves and future cash flows from those reserves, future production, oil and natural gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates. It is not possible to measure underground accumulations of oil or natural gas in an exact way. Estimating accumulations of oil and natural gas is a complex process that relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC. The accuracy of a reserve estimate is a function of:

- quality and quantity of available data;
- interpretation of that data; and
- accuracy of various mandated economic assumptions.

Any significant variance could materially affect the quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of development, changes in development schedule and exploration and prevailing oil and natural gas prices.

In accordance with SEC requirements, we base both our estimated quantities of reserves and our estimated discounted future net cash flows from our proved reserves on an un-weighted arithmetic average of the first-day-of-the month price for each month during the calendar year and on year-end costs. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate.

Future commodity price declines and/or increased capital costs may result in a write-down of our asset carrying values, which could adversely affect our results of operations and limit our ability to borrow funds. The value of our assets depend on crude oil and natural gas prices. Declines in these prices as well as increases in development costs, changes in well performance, delays in asset development or deterioration of drilling results may result in our having to make substantial downward adjustments to our estimated proved reserves, and accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments.

We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. If net capitalized costs of our oil and natural gas properties exceed fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties annually and at any time when events or circumstances indicate a review is necessary, based on estimated prices as of the end of the reporting period. The carrying value of oil and natural gas properties is computed on a field-by-field basis. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date even if oil or natural gas prices increase. While we did not incur any such impairment charges in 2009 or 2010, natural gas prices have decreased significantly below price levels at the time of the acquisition of our natural gas properties in 2006 and 2008. It is possible that further declines in commodity prices could prompt an impairment in the future, which could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our Credit Agreement.

Approximately 51% of our total estimated proved reserves at December 31, 2010 were proved undeveloped reserves and may be reclassified as unproved or may not ultimately be produced or developed. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our crude oil and natural gas reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated. The SEC generally requires that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time. Proved undeveloped reserves that are not timely developed are subject to possible reclassification as non-proved reserves. Substantial downward adjustments to our estimated proved reserves could have a material adverse effect on our financial condition, results of operations, and operating cash flows. In addition, our undeveloped reserves may not ultimately be developed or produced during the time periods we have planned, at the costs we have budgeted, or at all, which in turn may have a material adverse effect on our results of operations.

Competitive industry conditions may negatively affect our ability to conduct operations. Competition in the oil and gas industry is intense, particularly with respect to the acquisition of producing properties and of proved undeveloped acreage. Major and independent oil and natural gas companies actively bid for desirable oil and natural gas properties, as well as for the equipment, supplies, labor and services required to operate and develop their properties. Some of these resources may be limited and have higher prices due to current strong demand. Many of our competitors have financial resources that are substantially greater than ours, which may adversely affect our ability to compete within the industry.

Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry.

These larger companies may have a greater ability to continue drilling activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition, results of operations, and operating cash flows

Drilling is a high-risk activity. Our future success will partly depend on the success of our drilling program. In addition to the numerous operating risks described in more detail below, these drilling activities involve the risk that no commercially productive oil or natural gas reservoirs will be discovered. Also, we are often uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- obtaining government and tribal required permits;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- changes in regulations;
- compliance with governmental or landowner requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services, including experienced labor.

As a result, there can be no assurance that our anticipated production levels will be realized or that our estimates of proved reserves will not be negatively impacted. For example, although we expect that our Diatomite production will increase to 5,000 BOE/D by mid-2011, actual production from these assets could be significantly lower. During the first half of 2010, Diatomite production decreased primarily due to the inability to drill new wells pending the receipt of permits from the DOGGR. Although we have received such permits, the DOGGR is expected to issue new regulations for the development of Diatomite, the effect of which we are unable to determine until such regulations are issued.

The oil and natural gas business involves many operating risks that can cause substantial losses. The oil and gas business involves many operating risks, and insurance we maintain may not protect us against all of these risks. These risks include:

- fires;
- explosions;
- blow-outs;
- uncontrollable flows of oil, natural gas, formation water or drilling fluids;
- natural disasters;
- pipe or cement failures;
- casing collapses;
- embedded oilfield drilling and service tools;
- abnormally pressured formations;

- major equipment failures, including cogeneration facilities; and
- environmental hazards such as oil spills, natural gas leaks, pipeline ruptures and discharges of toxic gases.

If any of these events occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage or destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- investigatory and clean-up responsibilities;
- regulatory investigation and penalties;
- more stringent regulations applicable to our operations;
- suspension of operations; and
- repairs to resume operations.

If we experience any of these problems, our ability to conduct operations could be adversely affected. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us. In accordance with customary industry practices, we maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. For instance, we do not carry business interruption insurance. We may elect not to carry insurance if the cost of available insurance is excessive relative to the risks presented. In addition, we cannot insure fully against pollution and environmental risks. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition, results of operations, and operating cash flows. While we intend to obtain and maintain insurance coverage we deem appropriate for these risks, there can be no assurance that our operations will not expose us to liabilities exceeding such insurance coverage or to liabilities not covered by insurance.

We are subject to comprehensive and stringent existing and pending laws and regulations that could give rise to substantial liabilities from environmental contamination or otherwise adversely affect our cost, manner or feasibility of doing business. Our operations are regulated extensively at the federal, state, regional and local levels by environmental laws and regulations that impose limitations on our discharge of pollutants into the environment, establish standards for our management, treatment, storage, transportation and disposal of hazardous materials and solid and hazardous wastes, and impose obligations requiring us to investigate and remediate contamination resulting from our operations. In certain circumstances, we also must satisfy federal and state requirements for providing environmental assessments, environmental impact studies and/or plans of development before we commence exploration and production activities. Environmental requirements applicable to our operations generally have become more stringent in recent years, and compliance with those requirements has become more expensive. Frequently changing environmental laws and regulations have increased our costs to plan, design, drill, install, operate and abandon oil and natural gas wells and other facilities, and may impose substantial liabilities if we fail to comply with such regulations or for any contamination resulting from our operations. Our business results from operations and financial condition, results of operations, and operating cash flows may be adversely affected by any failure to comply with, or future changes to, these laws and regulations. In particular, failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal sanctions, including the payment of monetary penalties and the performance of remedial obligations.

From time to time we have experienced accidental spills, leaks and other discharges of contaminants at our properties. We could be liable for the investigation or remediation of such contamination, as well as claims for personal injury, property damage or natural resource damage arising from the contamination. We have incurred expenses and penalties in connection with contamination arising from our operations in the past, and we may do so in the future. Such liabilities may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate, and may arise because of our status as an owner or operator and not because of any noncompliance with applicable environmental laws. Under a number of environmental laws, including the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), such liabilities may be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. Some of the properties that we have acquired, or in which we may hold an interest but not operational control, may have past or ongoing contamination for which we may be held responsible. Some of our operations are in environmentally sensitive areas that may provide habitat for endangered or threatened species, and other protected areas, and our operations in such areas must satisfy additional regulatory requirements. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed certain drilling projects and/or access to prospective lands and have filed litigation in an attempt to overturn decisions granting the performance of such projects, including decisions made by the U.S. Bureau of Land Management regarding several leases in Utah that we have been awarded.

Climate change legislation or regulatory initiatives may adversely affect our operations, our cost structure, and the demand for the oil and natural gas that we produce. On December 15, 2009, the U.S. Environmental Protection Agency (EPA) published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) present an endangerment to public heath and the environment because emissions of such gasses are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Following issuance of this finding, the EPA adopted two sets of regulations under the Clean Air Act. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to "best available control technology" standards for GHG that have yet to be developed. With regard to the monitoring and reporting of GHGs, on December 17, 2010, the EPA amended the "Mandatory Reporting of Greenhouse Gases" rule (Reporting Rule), originally issued in September 2009. The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gases emissions annually on a facility-by-facility basis. Further, on November 8, 2010, EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA's GHG Reporting Rule. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO2 equivalent per year will now be required to report annual GHG emissions to EPA, with the first report due on March 31, 2012.

Similarly, legislation has been introduced in the United States Congress that would establish measures restricting greenhouse gas emissions in the United States. At the state level, over one-half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. The State of California has adopted legislation that caps California's GHG emissions at 1990 levels by

2020, and the California Air Resources Board (CARB) has implemented mandatory reporting regulations and is proceeding with early action measures to reduce GHG emissions prior to January 1, 2012. CARB is also developing regulations to implement a cap and trade program in 2012 to reduce GHG emissions. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Congress has, in the past, considered two companion bills for the "Fracturing Responsibility and Awareness of Chemicals Act" (the FRAC Act). While now dead, if reintroduced, the bills would repeal an exemption in the federal Safe Drinking Water Act (SWDA) for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of the FRAC Act have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. If reintroduced, the legislation would require the reporting and public disclosure of chemicals used in the fracturing process. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Further, if enacted, the FRAC Act could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of any future federal or state laws or implementing regulation imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing, complete natural gas wells in shale formations and increase our costs of compliance and doing business.

Our operations are subject to numerous federal, state and tribal regulations and laws; compliance with existing and future laws may increase our costs and delay our operations. Our activities are also subject to regulation by the federal government, oil and natural gas-producing states and one Native American tribe. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from federal, state, local and Native American tribal authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions that are more expensive than we have anticipated could have a negative effect on our ability to explore or develop our properties.

Changes to current tax laws may affect our ability to take certain deductions. Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, our ability to take certain deductions related to our operations, including depletion deductions, deductions for intangible drilling and development costs and deductions for United States production activities. These changes, if enacted into law, could negatively affect our financial condition, results of operations and operating cash flow.

Derivatives legislation enacted in 2010 could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. New comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission (the CFTC) to regulate certain markets for over-the-counter (OTC) derivative products. Currently, final rules to be adopted by the CFTC implementing the mandates of the new legislation are pending. Such rules would require certain derivatives to clear through clearinghouses. The effect on our business will depend in part on whether we are determined to be a major swap participant or swap dealer or a qualifying end-user, as those terms are defined in the final rules. We may be required to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities. The CFTC has proposed regulations that, if adopted, may exempt us from margin and clearing requirements, but the timing of adoption of such regulations, and their scope, is uncertain. Even if we are not deemed a major swap participant or swap dealer, the rules could impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. The legislation may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The legislation and any new regulations, including determinations with respect to the applicability of margin requirements and other trading structures, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

Property acquisitions are a component of our growth strategy, and our failure to complete future acquisitions successfully could reduce our earnings and slow our growth. Our business strategy has emphasized growth through strategic acquisitions, but we may not be able to continue to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. If we are unable to achieve strategic acquisitions, our growth may be impaired, thus impacting earnings, cash from operations and reserves.

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities. Our recent growth is due in part to acquisitions of properties with additional development potential and properties with minimal production at acquisition but significant growth potential, and we expect acquisitions will continue to contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include: recoverable reserves, exploration potential, future oil and natural gas prices, operating costs, production taxes, access rights and potential environmental and other liabilities. Such assessments are inexact, and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not allow us to become sufficiently familiar with the properties, and we do not always discover structural, subsurface, environmental and access problems that may exist or arise. Our review prior to signing a definitive purchase agreement may be even more limited.

We generally are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, on acquisitions. Often, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. If material breaches are discovered by us prior to closing, we could require adjustments to the purchase price or if the claims are significant, we or the seller may have a right to terminate the agreement. We could also fail to discover breaches or defects prior to closing and incur significant unknown liabilities, including environmental liabilities, or experience losses due to title defects, for which we would have limited or no contractual remedies or insurance coverage.

There are risks in making acquisitions, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of management attention, and costs of increased scope, geographic diversity and complexity of our operations. Increasing our reserve base through acquisitions is an important part of our business strategy. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, the future prices of oil and natural gas, revenues and costs, including synergies;
- an inability to integrate successfully the properties and businesses we acquire;
- a decrease in our liquidity to the extent we use a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

Our decision to acquire a property or business will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

If third-party pipelines interconnected to our natural gas wells and gathering facilities become partially or fully unavailable to transport our natural gas, our financial condition, results of operations and operating cash flows could be adversely affected. We depend upon third party pipelines that provide delivery options from our wells and gathering facilities. Since we do not own or operate these pipelines, their continuing operation in their current manner is not within our control. If any of these third-party pipelines become partially or fully unavailable to transport our natural gas, or if the natural gas quality specifications for their pipelines change so as to restrict our ability to deliver natural gas to those pipelines, our revenues and cash available for distribution could be adversely affected.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase. Section 1(b) of the Natural Gas Act (NGA) exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company, but the status of these lines has never been challenged before FERC. The distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress, and application of existing FERC policies to individual factual circumstances. Accordingly, the classification and regulation of some of our natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts, or Congress. In the event our gathering facilities are reclassified to FERC-regulated transmission services, we may be required to charge lower rates and our revenues could thereby be reduced.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. FERC has issued an order requiring certain participants in the natural gas market, including natural gas gatherers and marketers, which engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. In addition, FERC has issued an order requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three calendar years, to post daily certain information regarding the pipeline's capacity and scheduled flows for each receipt and delivery point that has design capacity equal to or greater than 15,000 MMBtu per day. Should we fail to comply with these requirements or any other applicable FERC-administered statute, rule, regulation or order, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

The loss of key personnel could adversely affect our business. We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could adversely affect our business, and we do not maintain key man insurance on the lives of any of these persons. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

We may not adhere to our proposed drilling schedule. Our final determination of whether to drill any scheduled or budgeted wells will depend on a number of factors, including:

- results of our exploration efforts and the acquisition, review and analysis of our seismic data, if any;
- availability of sufficient capital resources to us and any other participants for the drilling of the prospects;
- approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability and prices of drilling rigs and crews; and
- availability of leases, license options, farm-outs, other rights to explore and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. For instance, our drilling schedule may vary from our expectations because of future uncertainties and rig availability and access to our drilling locations utilizing available roads. In addition, we will not necessarily drill wells on all of our identified drilling locations on our acreage.

We may incur losses as a result of title deficiencies. We acquire from third parties, or directly from the mineral fee owners, working and revenue interests in the oil and natural gas leaseholds and estates upon which we will perform our exploration activities. The existence of a material title deficiency can reduce the value or render a property worthless, thus adversely affecting our financial condition, results of operations and operating cash flow. Title insurance covering mineral leaseholds is not always available, and when available is not always obtained. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and/or undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. In cases involving material title problems, the amount paid for affected oil and natural gas leases or estates can be generally lost, and a prospect can become undrillable.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information required by Item 2. Properties is included under Item 1. Business.

Item 3. Legal Proceedings

While we are, from time to time, a party to certain lawsuits in the ordinary course of business, we do not believe any of such existing lawsuits will have a material adverse effect on our operations, financial condition, or operating cash flows.

Executive Officers

Listed below are the names, ages (as of December 31, 2010) and positions of our executive officers and their business experience during at least the past five years. There are no family relationships between any of the executive officers and members of the Board of Directors.

ROBERT F. HEINEMANN, 57, has been President and Chief Executive Officer since June 2004. Mr. Heinemann was Chairman of the Board and interim President and Chief Executive Officer from April 2004 to June 2004. From December 2003 to March 2004, Mr. Heinemann acted as the director designated to serve as the presiding director at executive sessions of the Board in the absences of the Chairman and as liaison between the independent directors and the CEO. Mr. Heinemann joined the Board in March of 2002. From 2000 until 2002, Mr. Heinemann served as the Senior Vice President and Chief Technology Officer of Halliburton Company and as the Chairman of the Halliburton Technology Advisory Committee. He was previously with Mobil Oil Corporation (Mobil) where he served in a variety of positions for Mobil and its various affiliate companies in the energy and technical fields from 1981 to 1999, with his last responsibilities as Vice President of Mobil Technology Company and General Manager of the Mobil Exploration and Producing Technical Center.

DAVID D. WOLF, 40, has been Executive Vice President and Chief Financial Officer since August 2008. Mr. Wolf was previously employed by JPMorgan from 1995 to 2008 where he served as a Managing Director in JPMorgan's Oil and Gas Group and advised on numerous equity, debt and M&A transactions in the energy industry.

MICHAEL DUGINSKI, 44, has been Executive Vice President and Chief Operating Officer since September 2007. Mr. Duginski served as Executive Vice President of Corporate Development and California from October 2005 to August 2007; he acted as Senior Vice President of Corporate Development from June 2004 through October 2005 and as Vice President of Corporate Development from February 2002 through June 2004. Mr. Duginski, a mechanical engineer, was previously employed by Texaco, Inc. from 1988 to 2002 where his positions included Director of New Business Development, Production Manager and Gas and Power Operations Manager. Mr. Duginski is also an Assistant Secretary.

GEORGE T. CRAWFORD, 50, has been Senior Vice President of California Production since May 2009. Mr. Crawford served as Vice President of California Production from October 2005 until May 2009, Vice President of Production from December 2000 through October 2005 and as Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, previously served as the Production Engineering Supervisor for Atlantic Richfield Corp. from 1989 to 1998, with numerous engineering and operational assignments, including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

DAN ANDERSON, 48, has been Vice President of Rocky Mountains Production since October 2005. Mr. Anderson was Rocky Mountains Manager of Engineering from August 2003 through October 2005. Previously, Mr. Anderson, a petroleum engineer, served as a Senior Staff Petroleum Engineer with Williams Production RMT from August 2001 through August 2003. He also was a Senior Staff Engineer with Barrett Resources from October 2000 through August 2001. He previously held various engineering and management positions with Santa Fe Snyder Corporation and Conoco, Inc. from 1985 to 2000.

WALTER B. AYERS, 67, has acted as Vice President of Human Resources since May 2006. Mr. Ayers was previously a private consultant to the energy industry from January 2002 until his employment with the Company. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000.

SHAWN M. CANADAY, 35, has held the position of Vice President of Finance and Treasurer since August 2009. Mr. Canaday was Vice President and Controller from June 2008 until July 2009 and was Interim Chief Financial Officer from June 2008 until August 2008. Mr. Canaday served as Controller from February 2007 to July 2009, as Treasurer from December 2004 to February 2007 and as Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and gas industry since 1998 in various finance functions at Chevron and in public accounting. Mr. Canaday is also an Assistant Secretary.

GEORGE W. CIOTTI, 47, has held the position of Vice President, Corporate Development since January 2010. Mr. Ciotti was Manager of Business Development from January 2009 through December 2009 and Senior Financial Analyst from December 2007 until December 2008. Immediately prior to joining Berry, Mr. Ciotti was President and Founder of a consulting company focused on financial and business services. He also had ten years of experience with Texaco in positions such as Assistant Controller and Senior Project Economist.

DAVIS O. O'CONNOR, 56, has been the Vice President, General Counsel, and Secretary since October 2010. He previously served as a partner and an associate with the Denver law firm of Holland and Hart LLP since 1979 where he practiced in the areas of domestic and international business transactions including mergers, acquisitions, divestitures, joint ventures and related transactions, primarily in the oil and natural gas industry.

JAMIE L. WHEAT, 40, has held the position of Principal Accounting Officer since March 2010, and Controller since August 2009. Ms. Wheat was the Accounting Manager from August 2008 until August 2009. Prior to joining the Company, Ms. Wheat was a Senior Manager in the assurance practice group of KPMG, where she worked from 2001 to 2008.

PART II

Item 5. Market for the Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

Shares of Class A Common Stock and Class B 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 Class A Common Stock at the option of the holder.

Our Class A Common Stock is listed on the New York Stock Exchange under the symbol BRY. The Class B Stock is not publicly traded. The market data and dividends for 2010 and 2009 are shown below:

	2010			2009		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 31.27	$ 25.62	$ .075	$ 13.10	$ 5.50	$ .075
Second Quarter	34.30	25.57	.075	22.76	10.52	.075
Third Quarter	32.23	24.30	.075	28.46	14.90	.075
Fourth Quarter	44.80	30.65	.075	31.37	24.87	.075
Total Dividends Paid			$ .300			$ .300

The number of holders of record of our Class A Common Stock was 532 as of February 11, 2011. There was one Class B Shareholder of record as of February 11, 2011.

Dividends

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

Since our formation in 1985 through December 31, 2010, we have paid dividends on our Common Stock for 85 consecutive quarters, and previous to that for eight consecutive semi-annual periods. We intend to continue the payment of dividends, although future dividend payments will depend upon our level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors. Dividend payments are limited by covenants in our (i) Credit Agreement to the greater of $35 million or 75% of net income, and (ii) bond indentures to up to $20 million annually irrespective of our coverage ratio or net earnings if we have exhausted our restricted payments basket, and up to $10 million in the event we are in a non-payment default.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders (1)	2,017,225	$ 25.87	1,149,837
Equity compensation plans not approved by security holders	—	—	—

(1) Excludes 557,473 shares of restricted stock units for which the vesting period has not lapsed.

Issuer Purchases of Equity Securities

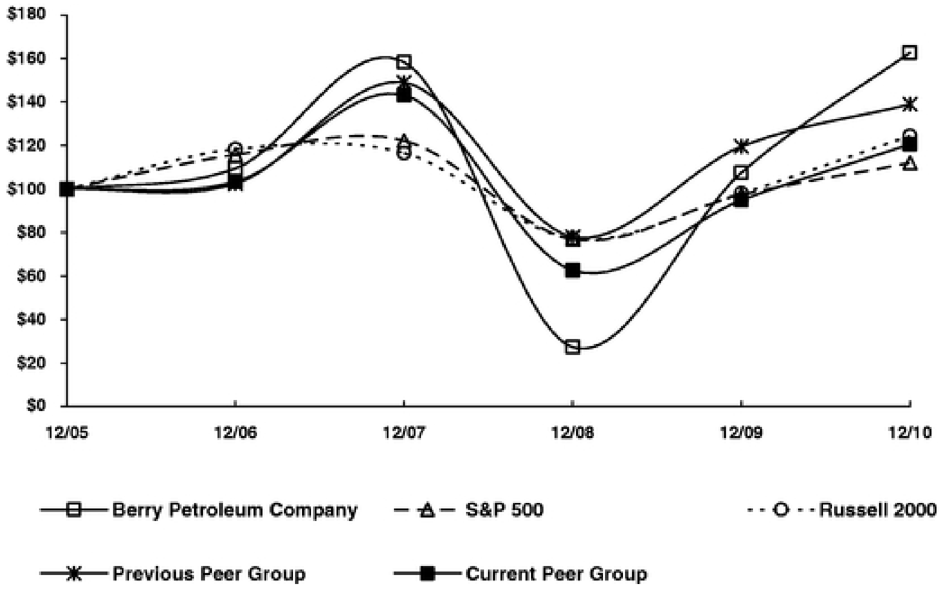
None.

Performance Graph

This graph shall not be deemed "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934 (the Exchange Act) or otherwise subject to the liabilities of that section, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933 or the Exchange Act, regardless of any general incorporation language in such filing.

Total returns assume $100 invested on December 31, 2005 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index and a Peer Group, assuming reinvestment of dividends for each measurement period. The information shown is historical and is not necessarily indicative of future performance. The 14 companies which make up the "Previous Peer Group" are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Forest Oil Corp., Petrohawk Energy Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Range Resources Corp., SM Energy Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp. The 14 companies which make up the "Current Peer Group" are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Forest Oil Corp., Penn Virginia Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Sandridge Energy Inc., SM Energy Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN
Among Berry Petroleum Company, the S&P 500 Index,
the Russell 2000 Index, Previous Peer Group and Current Peer Group



	12/05	12/06	12/07	12/08	12/09	12/10
Berry Petroleum Company	100.00	109.51	158.32	27.30	107.52	162.72
S&P 500	100.00	115.80	122.16	76.96	97.33	111.99
Russell 2000	100.00	118.37	116.51	77.15	98.11	124.46
Previous Peer Group	100.00	102.42	149.00	77.99	119.52	138.98
Current Peer Group	100.00	103.48	143.19	62.59	94.88	120.62

Item 6. Selected Financial Data

The following table sets forth certain financial information and is qualified in its entirety by reference to the historical financial statements and notes thereto included in Item 8. Financial Statements and Supplementary Data. The financial information at December 31, 2010 and 2009 and for the years ended December 31, 2010, 2009 and 2008 was derived from the Balance Sheets, Statements of Income, and Statements of Cash Flows in the audited financial statements and the accompanying notes to those financial statements included in Item 8. Financial Statements and Supplementary Data. The financial information at December 31, 2008, 2007 and 2006 and for the years ended December 31, 2007 and 2006 was derived from unaudited financial data not included in the report. The Statements of Income Data and Operating Data for the years ended December 31, 2009, 2008, 2007 and 2006 have been restated to reflect adjustments that are further discussed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 16 to the Financial Statements.

	Year Ended December 31,				
	2010	Restated 2009	Restated 2008	Restated 2007	Restated 2006
Statements of Income Data:					
Sales of oil and gas	$ 619,608	$ 500,532	$ 647,357	$ 422,480	$ 394,782
Sales of electricity	34,740	36,065	63,525	55,619	52,932
Gas marketing sales	22,162	22,806	35,750	—	—
Gain (loss) on sale of assets	—	826	(1,297)	54,173	103
Realized and unrealized (loss) gain on derivatives, net	(31,847)	(7,756)	(358)	—	736
Operating costs—oil and gas production	190,218	156,612	188,758	130,940	111,490
Operating costs—electricity generation	31,295	31,400	54,891	45,980	48,281
Gas marketing expense	19,896	21,231	32,072	—	—
Production taxes	22,999	18,144	26,876	14,651	12,169
General and administrative expenses (G&A)	52,846	49,237	54,279	39,663	36,474
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	179,432	139,919	125,595	82,861	61,419
Electricity generation	3,225	3,681	2,812	3,568	3,343
Earnings from continuing operations	82,524	47,224	120,577	120,666	96,808
Earnings from discontinued operations, net of income taxes	—	6,806	12,952	9,262	11,135
Net earnings	82,524	54,030	133,529	129,928	107,943
Net earnings from continuing operations per share, basic	1.54	1.03	2.67	2.71	2.18
Net earnings from discontinued operations per share, basic	—	0.15	0.29	0.20	0.26
Net earnings per share, basic	1.54	1.18	2.96	2.91	2.44
Net earnings from continuing operations per share, diluted	1.52	1.02	2.64	2.67	2.15
Net earnings from discontinued operations, diluted	—	0.15	0.28	0.20	0.25
Net earnings per share, diluted	1.52	1.17	2.92	2.87	2.40
Operating Data:					
Oil and gas producing continuing operations (per BOE):					
Average sales price(1)	$ 53.69	$ 41.23	$ 73.64	$ 52.30	$ 50.01
Average operating costs—oil and gas production	15.95	14.66	17.99	15.09	13.45
Production taxes	1.93	1.70	2.56	1.69	1.47
G&A	4.43	4.61	5.17	4.57	4.40
DD&A—oil and gas production	$ 15.05	$ 13.10	$ 11.97	$ 9.55	$ 7.41
Production—continuing operations (MBOE)	11,923	10,683	10,494	8,679	8,292

(1) Excludes all effects of derivatives. Please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information regarding the effect of derivatives on our average realized price.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
Balance Sheet and Other Data:					
Total assets	2,838,616	2,240,135	2,542,383	1,452,106	1,198,997
Long-term debt	1,108,965	1,008,544	1,131,800	445,000	390,000
Shareholders' equity	1,024,553	703,259	827,544	459,974	427,700
Dividends per share	0.30	0.30	0.30	0.30	0.30
Working capital deficit	(127,785)	(48,661)	(71,545)	(110,350)	(116,594)
Cash Flow Data:					
Cash flow from operations	367,237	212,576	409,569	238,879	258,475
Exploration and development of oil and gas properties	310,139	134,946	397,601	285,267	286,416
Property acquisitions	334,409	13,497	667,996	56,247	257,840

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with Item 6. Selected Financial Data and the accompanying financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward looking statements that reflect our future plans, estimates, beliefs and expected performance. Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed in Part I, Item 1A. Risk Factors, and elsewhere in this Annual Report on Form 10-K.

Restatement of Previously Issued Financial Statements

We have restated our historical financial statements for the years ended December 31, 2009, 2008, 2007 and 2006 to classify, as part of discontinued operations, realized gains (losses) on derivative instruments designated as cash flow hedges from the forecasted sale of natural gas produced by the DJ assets and amounts reclassified from Accumulated other comprehensive loss into earnings when the hedging relationship was discontinued.

At the time of the DJ asset sale, we had designated derivative instruments as cash flow hedges from the forecasted sale of natural gas produced by the DJ assets. We determined that as a result of the DJ asset sale, the forecasted transactions were no longer probable of occurring. Accordingly, we discontinued hedge accounting for those derivative instruments and the accumulated amount within Accumulated other comprehensive loss related to those derivatives was included in earnings from continuing operations. In addition, all recurring income statement impacts from derivatives designated as hedges of future production expected from the DJ assets were classified as continuing operations. We have determined that such items should be reflected in discontinued operations, and accordingly realized gains included in Sales of oil and gas of $6.2 million, $1.9 million, $10.7 million and $1.7 million were reclassified to discontinued operations for the years ended December 31, 2009, 2008, 2007 and 2006, respectively. A realized gain of $14.3 million included in Realized and unrealized (loss) gain on derivatives, net was reclassified to discontinued operations for the year ended December 31, 2009.

The effect of correcting the classification of these gains resulted in a decrease in earnings from continuing operations of $12.7 million, $1.2 million, $6.6 million and $1.0 million for the years 2009, 2008, 2007 and 2006, respectively, and increased net earnings from discontinued operations by the same amounts. The correction did not change total net earnings from both continuing and discontinued operations. The restatement also resulted in changes to the amounts previously reported as average realized prices for continuing operations. The following discussion gives effect to these corrections. See Note 16 to the Financial Statements.

Overview

The profitability of our operations in any particular accounting period will be directly related to the realized prices of oil, gas and electricity sold, the type and volume of oil and gas produced and electricity generated and the results of development, exploitation, acquisition and hedging activities. The realized prices for natural gas and electricity will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by global supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. We benefit from lower natural gas prices as we are a consumer of natural gas in our California operations. In the Permian, Uinta, E. Texas and Piceance we benefit from higher natural gas pricing. The cost of natural gas used in our steaming operations and electrical generation, production rates, labor, equipment costs, maintenance expenses, and production taxes are expected to be the principal influences on operating costs. Accordingly, our results of operations may fluctuate from period to period based on the foregoing principal factors, among others.

Notable Items in 2010

- Increased total production by 12% to 32,670 BOE/D, of which 66% was crude oil
- Generated discretionary cash flow of $391 million with an operating margin of 35.96 per BOE[(1)]
- Increased total reserves by 15% to 271 MMBOE and replaced 400% of production
- Increased oil reserves by 28% to 61% of total reserves
- Received approval from the DOGGR for the next phase of development of our Diatomite asset
- Increased Diatomite acreage by 20% through acquisition of an adjoining lease
- Announced commercial development of the McKittrick 21Z cyclic development
- Acquired 19,791 net acres in the Wolfberry Trend in the Permian with over 400 drilling locations on 40-acre spacing
- Executed a three rig drilling program in the Permian and exited 2010 at 2,550 BOE/D
- Opened our regional office in Midland, Texas and fully staffed our Permian asset team
- Settled our claim in the Flying J bankruptcy and received payment of $60.5 million
- Issued 8 million shares of Class A Common Stock and $300 million of 6.75% senior notes due 2020

Notable Items and Expectations for 2011

- Anticipating average production between 37,000 and 39,000 BOE/D, a 13% to 19% increase over 2010
- Expecting Permian production to average approximately 5,200 BOE/D in 2011
- Expecting Diatomite production to be approximately 5,000 BOE/D by mid-2011
- Moving forward with the full development of Ethel D steam flood
- Continuing to evaluate acquisition opportunities that fit into our core areas of operation
- Planning to invest approximately 90% of 2011 capital budget in our oil assets and increase our oil production mix to 70%

2011 Capital Budget

We expect our 2011 capital budget to range between $375 million and $425 million assuming an average commodity price of $75 WTI, which we expect to fund with net cash provided by our operating activities. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we may adjust our capital budget accordingly or adjust borrowings under our Credit Agreement, as needed. Approximately 90% of our 2011 capital expenditure budget is directed towards our oil assets, targeting oil production growth of approximately 20%.

Results of Operations

We had net earnings of $82.5 million, or $1.52 per diluted share, and cash provided from operations of $367.2 million in 2010. Net earnings includes a settlement from Flying J of $36.6 million, offset by a $31.3 million loss on derivatives as a result of non-cash changes in fair values and amortization of frozen values (as discussed below), $0.9 million of dry hole costs and $1.6 million of transaction-related costs associated with the acquisition of certain properties in the Permian.

In the fourth quarter of 2010, we had a net loss of $21.1 million, or $0.40 per diluted share, and cash provided by operations of $48.7 million. Net loss includes a $39.5 million loss on derivatives as a result of non-cash changes in fair values and amortization of frozen values. We drilled 83 gross wells during the quarter, and capital expenditures, excluding capitalized interest and property acquisitions, totaled $79.2 million. We achieved average production of 34,500 BOE/D in the fourth quarter of 2010, up 2% from the third quarter of 2010, primarily due to our increased drilling activity in the Permian.

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(1) Discretionary cash flow and operating margin are considered non-GAAP performance measures and reference should be made to "Reconciliation of Non-GAAP Measures" at the end of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for further explanation of these performance measures, as well as reconciliation to the most directly comparable GAAP measure.

The following table sets forth selected operating data for the years ended December 31:

	2010	%	Restated(a) 2009	%	2008	%
Oil and Gas						
Heavy oil production (BOE/D)	17,124	52	16,842	56	16,633	52
Light oil production (BOE/D)	4,589	14	2,846	10	3,697	12
Total oil production (BOE/D)	21,713	66	19,688	66	20,330	64
Natural gas production (Mcf/D)	65,720	34	62,074	34	69,834	36
Total production (BOE/D)	32,666	100	30,034	100	31,968	100
Less DJ production	—		765		3,295	
Production—continuing operations (BOE/D)	32,666		29,269		28,673	
Oil and gas, per BOE, from continuing operations:						
Average realized sales price	$ 52.14		$ 46.72		$ 73.64	
Average sales price including cash derivative settlements	$ 53.84		$ 46.02		$ 61.85	
Oil, per Bbl, from continuing operations:						
Average WTI price	$ 79.59		$ 62.09		$ 99.75	
Price sensitive royalties(b)	(3.06)		(2.04)		(2.95)	
Gravity differential and other(c)	(8.92)		(9.08)		(11.32)	
Crude oil derivatives non-cash amortization(d)	(2.59)		—		—	
Crude oil derivatives cash settlements(e)	—		7.47		(16.89)	
Correction to royalties payable(f)	—		(0.24)		1.42	
Oil revenue per BOE	65.02		58.20		70.01	
Add: Crude oil derivatives non-cash amortization(d)	$ 2.59		$ —		$ —	
Crude oil derivatives cash settlements(g)	(0.90)		(0.92)		—	
Average realized price	$ 66.71		$ 57.28		$ 70.01	
Natural gas, per Mcf, from continuing operations:						
Average Henry Hub price per MMBtu	$ 4.39		$ 4.00		$ 9.04	
Conversion to Mcf	0.22		0.20		0.46	
Natural gas derivatives non-cash amortization(d)	0.08		—		—	
Natural gas derivative cash settlements(e)	—		0.23		0.10	
Location, quality differentials and other	(0.24)		(0.59)		(2.59)	
Natural gas revenue per Mcf	4.45		3.84		7.01	
Less: Natural gas derivatives non-cash settlements	(0.08)		—		—	
Natural gas derivative cash settlements(g)	0.37		(0.04)		—	
Average realized natural gas price per Mcf	$ 4.74		$ 3.80		$ 7.01	

(a) See Note 16 to the Financial Statements.

(b) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above a base price which was $16.76 per barrel in 2010 as long as we maintain a minimum steam injection level. We met the steam injection level in 2010 and expect to meet the requirement going forward. This base price escalates at 2% annually; therefore, it is $17.09 per barrel in 2011. Formax production in 2010 was 2,240 BOE/D.

(c) In California, the differential at December 31, 2010 was $6.43 and ranged from a low of $5.78 to a high of $8.95 per barrel during the year. In Utah, the differential at December 31, 2010 was $15.00 and ranged from a low of $10.00 to a high of $15.00 per barrel during the year, based on oil postings.

(d) 2010 amount includes non-cash amortization of frozen December 31, 2009 fair values, resulting from discontinuing hedge accounting as of January 1, 2010, recorded in Sales of oil and gas.

(e) Includes cash settlements on derivatives prior to January 1, 2010, for which we had elected hedge accounting, recorded in Sales of oil and gas.

(f) 2009 amount includes a correction to one of our royalties payable in the amount of $1.9 million, which resulted in decreasing our Sales of oil and gas and increasing our royalties payable. Included in 2008 is a correction to our price-sensitive royalty in the amount of $10.5 million, which resulted in increasing our Sales of oil and gas and decreasing our royalties payable.

(g) Includes cash settlements on derivatives recorded in Realized and unrealized (loss) gain on derivatives, net.

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The following table sets forth selected operating data for the three months ended:

	December 31, 2010	%	Restated(a) December 31, 2009	%	September 30, 2010	%
Oil and Gas						
Heavy oil production (BOE/D)	16,548	48	17,280	60	16,722	49
Light oil production (BOE/D)	6,131	18	2,719	9	5,049	15
Total oil production (BOE/D)	22,679	66	19,999	69	21,771	64
Natural gas production (Mcf/D)	70,828	34	54,899	31	72,576	36
Total production—continuing operations (BOE/D)	34,484	100	29,149	100	33,867	100
Oil and gas, per BOE, from continuing operations :						
Average realized sales price	$ 53.55		$ 48.77		$ 48.73	
Average sales price including cash derivative settlements	53.75		47.08		51.88	
Oil, per Bbl, from continuing operations:						
Average WTI price	$ 85.20		$ 76.13		$ 76.20	
Price sensitive royalties(b)	(3.37)		(2.64)		(2.91)	
Quality differential and other(c)	(9.16)		(9.63)		(8.87)	
Crude oil derivatives non-cash amortization(d)	(3.22)		—		(2.89)	
Crude oil derivatives cash settlements(e)	—		(3.96)		—	
Correction to royalties payable(f)	—		(1.78)		—	
Oil revenue per BOE	$ 69.45		$ 58.12		$ 61.53	
Add: Crude oil derivatives non-cash amortization(d)	3.22		—		2.89	
Crude oil derivative cash settlements(g)	(4.35)		(2.16)		1.14	
Average realized oil price	$ 68.32		$ 55.96		$ 65.56	
Natural gas, per Mcf, from continuing operations:						
Average Henry Hub price per MMBtu	3.80		4.17		4.38	
Conversion to Mcf	0.19		0.21		0.22	
Natural gas derivatives non-cash amortization(d)	0.05		—		0.09	
Natural gas derivatives cash settlements(e)	—		0.40		—	
Location, quality differentials and other	(0.14)		(0.12)		(0.40)	
Natural gas revenue per Mcf	$ 3.90		$ 4.66		$ 4.29	
Less: Natural gas derivatives non-cash settlements	(0.05)		—		(0.09)	
Natural gas derivative cash settlements(g)	0.50		(0.11)		0.35	
Average realized natural gas price per Mcf	$ 4.35		$ 4.55		$ 4.55	

(a) See Note 16 to the Financial Statements.

(b) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above a base price which was $16.76 per barrel in 2010 as long as we maintain a minimum steam injection level. We met the steam injection level in 2010 and expect to meet the requirement going forward. This base price escalates at 2% annually; therefore, it is $17.09 per barrel in 2011. Formax production for the three months ended December 31, 2010 was 2,260 BOE/D.

(c) In California, the differential at December 31, 2010 was $6.43 and ranged from a low of $5.78 to a high of $8.95 per barrel during the year. In Utah, the differential at December 31, 2010 was $15.00 and ranged from a low of $10.00 to a high of $15.00 per barrel during the year, based on oil postings.

(d) 2010 amount includes non-cash amortization of frozen December 31, 2009 fair values, resulting from discontinuing hedge accounting as of January 1, 2010, recorded in Sales of oil and gas.

(e) Includes cash settlements on derivatives prior to January 1, 2010, for which we had elected hedge accounting, recorded in Sales of oil and gas.

(f) 2009 amount includes a correction to one of our royalties payable in the amount of $1.9 million, which resulted in decreasing our Sales of oil and gas and increasing our royalties payable.

(g) Includes cash settlements on derivatives recorded in Realized and unrealized (loss) gain on derivatives, net.

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The following table reflects results from continuing operations, (in millions except per share data):

	Twelve months ended,			Three months ended,		
		Restated(1)			Restated(1)	
	December 31, 2010	December 31, 2009	December 31, 2008	December 31, 2010	December 31, 2009	September 30, 2010
Sales of oil	$ 513	$ 420	$ 519	$ 143	$ 109	$ 123
Sales of gas	107	80	128	25	24	29
Sales of oil and gas	$ 620	$ 500	$ 647	$ 168	$ 133	$ 152
Sales of electricity	35	36	64	8	10	9
Gas marketing	22	23	36	4	5	5
Realized and unrealized (loss) gain on derivatives, net	(32)	(8)	—	(62)	—	(27)
Settlement on Flying J bankruptcy claim	22	—	—	—	—	—
Gain (loss) on sale of assets	—	1	(1)	—	—	—
Interest and other income, net	3	2	3	1	—	—
Total revenues and other income	$ 670	$ 554	$ 749	$ 119	$ 148	$ 139
Net earnings (loss) from continuing operations	$ 83	$ 47	$ 121	$ (21)	$ 13	$ (3)
Diluted earnings (loss) per share from continuing operations	$ 1.52	$ 1.02	$ 2.64	$ (0.40)	$ 0.29	$ (0.06)

(1) See Note 16 to the Financial Statements.

Sales of Oil and Gas

Sales of oil and gas increased $120 million, or 24%, in 2010 compared to 2009. The increase was due primarily to a 12% increase in production volumes and an increase in the average sales price to $52.14 per BOE in 2010 from $46.72 per BOE in 2009. Sales of oil and gas for the year ended December 31, 2010 include non-cash derivative losses of $18.4 million relating to the impact of de-designated hedges reclassified from Accumulated other comprehensive loss (AOCL). See Note 8 to the Financial Statements. Sales of oil and gas decreased 23% in 2009 compared to 2008. The decrease was primarily due to a 37% decrease in the average realized sales price to $46.72 per BOE in 2009 from $73.64 per BOE in 2008, offset by a 2% increase in production volumes.

Production from continuing operations increased 3,397 BOE/D, or 12% in 2010 compared to 2009. The increase was due to our 2010 development activities and the contribution of our acquisitions in the Permian. In 2010, we drilled a total of 232 net wells compared to 132 net wells drilled in 2009. Production from continuing operations increased 596 BOE/D, or 2%, in 2009 compared to 2008. The increase was the result of additional development activities during the year in the Diatomite and the benefit of a full year of E. Texas production in 2009. These increases were offset by decreases in the Uinta, the S. Midway field and the Piceance where there was very little capital activity in 2009.

Sales of Electricity

Sales of electricity decreased $1.4 million in 2010 compared to 2009 as a result of a $1.7 million adjustment received in 2009 due to a retroactive revision to the 2008 PG&E As-Delivered Capacity payment calculation. Sales of electricity decreased in 2009 by $27.4 million compared to 2008 as a result of 34% lower electricity prices. Electricity operating costs decreased in 2009 compared to 2008 due to 51% lower natural gas prices.

We purchased approximately 27,000 MMBtu/D of natural gas as fuel in our cogeneration facilities for the years ended December 31, 2010, 2009 and 2008. We purchase and transport, on average, 12,000 MMBtu/D on the Kern River Pipeline under our firm transportation contract and use this gas to produce conventional and cogeneration steam.

The following table is for the years ended December 31:

	2010	2009	2008
Electricity			
Revenues (in millions)	$ 34.7	$ 36.1	$ 63.5
Operating costs (in millions)	$ 31.3	$ 31.4	$ 54.9
Electric power produced—MWh/D	2,088	2,098	2,063
Electric power sold—MWh/D	1,925	1,907	1,873
Average sales price/MWh (no hedging was in place)	$ 60.68	$ 60.99	$ 92.98
Fuel gas cost/MMBtu (including transportation)	$ 4.49	$ 3.86	$ 7.90

Natural Gas Marketing

We have long-term firm transportation contracts on the Rockies Express pipeline for our Piceance natural gas production, with total capacity of 35,000 MMBtu/D. We pay a demand charge for the full amount of this capacity; however, at the present time our own production is insufficient to fully utilize this capacity. In order to maximize the value of this transportation, we purchased our partner's working interest share of gas produced at the market rate for the producing area and entered into FERC-approved Asset Management Agreements with our marketers whereby they fill any remaining unused capacity. The Rockies Express pipeline moves the gas to a location near Lebanon, Ohio where we receive a price based on that sales point. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Statements of Income for the years ended December 31, 2010, 2009 and 2008 was $2.3 million, $1.6 million and $3.7 million, respectively. Firm transportation costs related to all of our Rockies Express pipeline volumes is reflected in Operating costs—oil and gas production and totaled $12.5 million, $13.7 million and $8.0 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Realized and Unrealized (Loss) Gain on Derivatives, Net

Realized and unrealized (loss) gain on derivatives, net is primarily related to derivatives for which we did not elect hedge accounting or derivatives which did not qualify for cash flow hedge accounting either at their inception or where hedge accounting was discontinued during their term. When the criteria for cash flow hedge accounting is not met, or when cash flow hedge accounting is not elected, realized gains and losses (*i.e*., cash settlements) are recorded in Realized and unrealized (loss) gain on derivatives, net in the Statements of Income. Similarly, changes in the fair value of the derivative instruments are recorded as unrealized gains or losses in Realized and unrealized (loss) gain on derivatives, net in the Statements of Income. In contrast, cash settlements for derivative instruments that qualify for hedge accounting are recorded as additions to or reductions of Sales of oil and gas or interest expense, while changes in fair value of cash flow hedges are recognized, to the extent the hedge is effective, in AOCL until the hedged item is recognized in earnings. Realized and unrealized (loss) gain on derivatives, net also includes any hedge ineffectiveness on cash flow hedges that qualify for hedge accounting.

During 2009, we entered into certain commodity derivative contracts that we did not designate as cash flow hedges. In addition, effective January 1, 2010, we elected to de-designate all of our commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. Accordingly, beginning January 1, 2010 derivative contract fair value gains and losses are recognized immediately in earnings. Cash flow is impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty and such cash settlement gains and losses are also recorded to earnings under the caption Realized and unrealized (loss) gain on derivatives, net.

The following table sets forth the cash settlements and non-cash fair value gains and losses for the derivative contracts not designated as hedges recorded in Realized and unrealized (loss) gain on derivatives, net for the years ended December 31:

	2010	2009	2008
		(in thousands)	
Cash receipts (payments):			
Commodity derivatives—oil	$ (7,078)	$ (6,671)	$ —
Commodity derivatives—natural gas	8,889	(888)	—
Financial derivatives—interest(1)	(17,499)	—	—
Total cash receipts (payments)	$ (15,688)	$ (7,559)	$ —
Fair value gain (loss):			
Commodity derivatives—oil	$ (37,440)	$ —	$ —
Commodity derivatives—natural gas	12,424	355	—
Financial derivatives—interest(1)	8,857	—	—
Total fair value gain (loss)	$ (16,159)	$ 355	$ —
Total Realized and unrealized (loss) gain on derivatives, net	$ (31,847)	$ (7,204)	$ —

(1) In the fourth quarter of 2010, we terminated certain interest rate derivative instruments previously designated as cash flow hedges. The termination resulted in a cash settlement of $10.8 million, offset by a fair value gain of $8.9 million.

During the year ended December 31, 2009, we recorded $0.6 million under the caption Realized and unrealized (loss) gain on derivatives, net as a result of ineffectiveness on cash flow hedges.

Settlement of Flying J Bankruptcy

On July 6, 2010, the Joint Plan of Reorganization of Flying J, Inc., Big West of California, LLC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United State Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of our claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, we and Flying J agreed that the total amount owed to us by Flying J for the purchases of our California production and other damages was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010.

Oil and Gas Operating and Other Expenses

The following table presents information about our continuing operating expenses for each of the years ended December 31:

	Amount per BOE			Amount (in thousands)		
	2010	2009	2008	2010	2009	2008
Operating costs—oil and gas production	$ 15.95	$ 14.66	$ 17.99	$ 190,218	$ 156,612	$ 188,758
Production taxes	1.93	1.70	2.56	22,999	18,144	26,876
DD&A—oil and gas production	15.05	13.10	11.97	179,432	139,919	125,595
G&A	4.43	4.61	5.17	52,846	49,237	54,279
Interest expense	5.58	4.67	2.28	66,541	49,923	23,942
Total	$ 42.94	$ 38.74	$ 39.97	$ 512,036	$ 413,835	$ 419,450

- Operating costs were $190 million in 2010, an increase of 21% compared to $157 million in 2009. On a per BOE basis, operating costs increased 9% to $15.95 per BOE from $14.66 per BOE. Our 2010 operating costs increased primarily due to higher steam costs resulting from higher volumes of injected steam and higher fuel cost/MMBtu. In addition, the increase in operating costs was due to higher expenditures for well workovers and higher compression, gathering, and dehydration costs. Operating cost were $157 million in 2009, a decrease of 17% compared to $189 million in 2008. On a per BOE basis operating costs decreased 19% to $14.66 per BOE from $17.99 per BOE. The decrease was primarily due to a 51% decrease in fuel gas cost/MMBtu, offset by higher volumes of injected steam.

  The following table presents steam information for each of the years ended December 31:

	2010	2009	2008
Average volume of steam injected (Bbl/D)	116,956	109,153	99,908
Fuel gas cost/MMBtu (including transportation)	$ 4.49	$ 3.86	$ 7.90
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	36,020	30,462	26,826

- Production taxes were $23 million in 2010, an increase of 27% compared to $18 million in 2009. On a per BOE basis, production taxes increased 14% to $1.93 per BOE in 2010 from $1.70 per BOE in 2009. The increase in production taxes, on a per barrel basis, was primarily due to an increase in the assessed ad valorem values attributed to our California properties. In addition, our West Texas and Utah properties contributed to a higher cost per BOE due to severance taxes tied to the field sales price of the commodity. Production taxes were $18 million in 2009, a decrease of 32% compared to $27 million in 2008. On a per BOE basis, production taxes decreased 34% to $1.70 per BOE in 2009 from $2.56 in 2008. The decrease in production taxes, on a per barrel basis, was primarily due to a decrease in the assessed ad valorem values attributed to our California properties and a decrease in severance taxes in Utah, Colorado and Texas, which are directly related to the field sales price of the commodity.

- Depreciation, depletion and amortization (DD&A) was $179 million in 2010, an increase of 28% compared to $140 million in 2009. On a per BOE basis, DD&A increased 15% to $15.05 per BOE in 2010 from $13.10 per BOE in 2009. The increase in DD&A per BOE was primarily due to the contribution of our development properties with higher drilling and leasehold acquisition costs than our California properties, including our recent acquisitions in the Permian and a shift in production volumes to assets outside of California. In 2010, 52% of our production volumes were heavy oil produced in California, compared to 56% of our production volumes in 2009. DD&A was $140 million in 2009, an increase of 11% compared to $126 million in 2008. On per BOE basis, DD&A increased 9% to $13.10 per BOE in 2009 from $11.97 per BOE in 2008. The increase in DD&A per BOE was primarily due to an increase in the contribution of our development properties with higher drilling and leasehold acquisition costs than our California properties, including our E. Texas assets acquired mid-year 2008.

- General and administrative expense (G&A) was $53 million in 2010, an increase of 7% compared to $49 million in 2009. On a per BOE basis, G&A decreased 4% to $4.43 per BOE in 2010 from $4.61 per BOE in 2009. The increase between periods was due to higher employee-benefit costs, including bonus costs. As of December 31, 2010, we had 270 full-time employees compared to 243 as of December 31, 2009. A significant driver in the increase in employee headcount has been our acquisitions in the Permian and additional personnel required for our capital program and production levels. The decrease in G&A per BOE in 2010 compared to 2009 was due to increased production. G&A was $49 million in 2009, a decrease of 9% compared to $54 million in 2008. On a per BOE basis, G&A decreased 11% to $4.61 per BOE in 2009 from $5.17 in 2008. The decrease between periods was due to a 20% decrease in personnel associated with the sale of our DJ assets, offset by $2.1 million recorded in the second quarter of 2009 for a regulatory compliance matter. In addition, in 2008 we moved our headquarters from Bakersfield, California to Denver, Colorado and incurred relocation and related expenses for our employees of approximately $1.7 million. Also included in G&A in 2008 was $2.3 million in rig termination penalties that we incurred during the fourth quarter of 2008.

- Interest expense was $67 million in 2010, an increase of 33% compared to $50 million in 2009. On a per BOE basis, interest increased 19% to $5.58 in 2010 from $4.67 in 2009. Interest expense in 2010 included non-cash derivative losses of $8.3 million, or $.70 per BOE related to the de-designated interest rate hedges reclassified from AOCL into interest expense. In addition, interest expense increased due to an entire year of interest charges associated with our 10.25% senior notes due 2014 and interest on our 6.25% senior notes due 2020, issued in November 2010, offset by a decrease in interest charges associated with our Credit Agreement. Interest expense was $50 million in 2009, an increase of 109% compared to $24 million in 2008. On a per BOE basis, interest expense increased 105% to $4.67 per BOE in 2009 from $2.28 per BOE in 2008. The increase in interest expense between periods is due to additional interest charges associated with the issuance of the 10.25% senior notes due 2014, which were issued in June and August of 2009 and higher interest charges on our Credit Agreement.

Extinguishment of Debt. We recorded debt extinguishment costs of $0.6 million in 2010 and $10.8 million in 2009. In 2010, we wrote off costs associated with borrowing base changes under our Credit Agreement. In 2009, we wrote off costs associated with borrowing base changes under Credit Agreement and fees associated with the extinguishment of our second lien term loan. See Note 3 to the Financial Statements.

Transaction Costs on Acquisitions. In 2010, we incurred $2.6 million of acquisition related expenses for the acquisition of certain properties in the Permian. See Note 2 to the Financial Statements.

Dry Hole, Abandonment, Impairment and Exploration. We recorded dry hole, abandonment and impairment charges of $1.5 million, $5.2 million and $9.9 million in 2010, 2009 and 2008, respectively. In 2010, we recorded dry hole, abandonment, and impairment expense primarily due to a mechanical failure encountered on one well in the Piceance. The well was abandoned in favor of drilling a replacement well from the same well pad. In 2009, we recorded dry hole, abandonment and impairment expense primarily due to a $4.2 million impairment charge related to the write-down of a rig to its fair market value. See Note 9 to the Financial Statements. In 2008, we recorded dry hole, abandonment and impairment charges primarily due to $7.3 million for technical difficulties that were encountered on five wells in the Piceance before reaching total depth. These holes were abandoned in favor of drilling to the same bottom-hole location by drilling new wells. Additionally, in 2008, we recorded an impairment charge of $2.4 million related to the write-down of a rig to its fair market value.

We incurred exploration costs in 2010, 2009 and 2008, of $0.8 million, $0.2 million and $0.6 million, respectively. These costs consist primarily of geological and geophysical costs.

Bad Debt (Recovery) Expense. We recognized $38.5 million in bad debt expense in the year ended December 31, 2008 related to the Flying J, bankruptcy. On July 6, 2010, the Joint Plan of Reorganization of Flying J was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the Stipulation, pursuant to which Flying J agreed that the total amount owed to us by Flying J was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010. In the quarter ended September 30, 2010, we recorded a settlement of our Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

Income Tax Expense. The effective tax rate for the years ended December 31, 2010, 2009, and 2008 was 40%, 30% and 37%, respectively. In 2009, the effective income tax rate was impacted by reduced state rates and a decrease in our liability related to uncertain income tax positions. Our estimated annual effective income tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences. See Note 4 to the Financial Statements.

Estimated 2011 Oil and Gas Operating, G&A and Interest Expense. We estimate our 2011 production volume will range between 37,000 BOE/D and 39,000 BOE/D. Based on WTI of $75.00 and NYMEX HH of $4.50 MMBtu, we expect our oil and gas operating and other expenses to be within the following ranges:

	Amount per BOE		
	Anticipated range in 2011	2010	2009
Operating costs—oil and gas production(1)	$ 16.50 - 18.50	$ 15.95	$ 14.66
Production taxes(2)	2.00 - 2.50	1.93	1.70
DD&A(3)	16.00 - 18.00	15.05	13.10
G&A	3.75 - 4.25	4.43	4.61
Interest expense	5.25 - 6.25	5.58	4.67
Total	$ 43.50 - 49.50	$ 42.94	$ 38.74

(1) We expect Operating costs—oil and gas production to increase in 2011 as compared to 2010 due to a larger contribution of production from our oil properties.

(2) We expect production taxes will be higher on a per BOE basis as our average realized price increases due to higher commodity prices.

(3) We expect DD&A will increase in 2011 as a result of the contribution of our Permian assets, which have higher finding and development costs than our legacy assets.

Financial Condition, Liquidity and Capital Resources

Our development, exploitation and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and our Credit Agreement as our primary sources of liquidity. We have also used debt and equity markets as other sources of financing and, as market conditions have permitted, we have engaged in asset monetization transactions. As we pursue profitable reserves and production growth, we continually monitor the capital resources, including issuance of equity and debt securities, available to us to meet our future financial obligations, planned capital expenditure activity and liquidity. We believe that we have significant liquidity available to us from cash flows from operations and under our Credit Agreement for our planned uses of capital.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flows. As of December 31, 2010, we have approximately 65% and 40% of our expected 2011 and 2012 oil production hedged in the form of swaps and collars. This level of derivatives is expected to provide a measure of certainty of the cash flows that we will receive for a portion of our production in 2011 and 2012. In the future, we may determine to increase or decrease our derivative positions. Most of our derivatives counterparties were commercial banks that are parties to our Credit Agreement, or their affiliates. See Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk below for further details concerning our hedging activities.

On November 15, 2010, we entered into our Credit Agreement, which extended the maturity date of our prior facility to November 13, 2015. The Credit Agreement has a current borrowing base and lender commitments of $875 million, after the reduction to the borrowing base resulting from our recent issuance of $300 million of 6.75% senior notes. The maximum amount available is subject to semi-annual redeterminations of the borrowing base based on the value of our proved oil and natural gas reserves, in April and October of each year in accordance with the lenders' customary procedures and practices. Both we and the banks have the bilateral right to one additional redetermination each year. The Credit Agreement is required to be secured by oil and natural gas properties representing at least 80% of the present value of our proved reserves. The LIBOR and prime rate margins are between 1.75% and 2.75% 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%. The Credit Agreement also provides the right for us to refinance our 10.25% Senior Notes due 2014 (2014 Notes) with similar notes or retire the 2014 Notes using available borrowing under the Credit Agreement as long as certain leverage and liquidity tests are met.

On November 23, 2010, we amended our unsecured uncommitted money market line of credit (Line of Credit), increasing the maximum borrowings from $30 million to $40 million. Borrowings under the Line of Credit may be outstanding for a maximum of 30 days, subject to interest charged at LIBOR plus a margin of approximately 1.4%. See Note 3 to the Financial Statements.

Our total outstanding debt at December 31, 2010 under the Line of Credit and Credit Agreement was $175.3 million, and $23.2 million of letters of credit have been issued under the Credit Agreement, leaving $676.5 million in borrowing capacity available.

The Credit Agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. The Credit Agreement requires us to maintain (i) an interest coverage ratio, as defined, of 2.75 to 1.0 and (ii) a minimum current ratio, as defined, of 1.0 to 1.0. We are currently in compliance with all financial covenants and have complied with all financial covenants for all prior periods presented.

The debt and equity markets have served as our primary source of financing to fund large acquisitions and other transactions. In January 2010, we sold to the public 8 million shares of our common stock at a price of $29.25 per share and received $224 million of net proceeds. We used the net proceeds to fund an acquisition in the Permian in March 2010 and reduce our outstanding borrowings under our Credit Agreement. In November 2010, we issued $300 million in principal amount of 6.75% senior notes due 2020 and received net proceeds of $294 million, which were used in part to finance an acquisition in the Permian in November 2010. The remainder was used to reduce outstanding borrowings under our Credit Agreement. In May 2009, we issued $325 million principal amount of 10.25% senior notes due 2014 and in August 2009 we issued an additional $125 million principal amount of our 10.25% senior notes due 2014. We used the net proceeds to reduce our outstanding borrowings under the Credit Agreement and to repay the second lien term loan. See Note 3 to the Financial Statements.

Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control.

We have also engaged in asset dispositions to generate additional cash to fund expenditures and further enhance our financial flexibility. In April 2009, we sold our DJ assets for $140 million before customary closing adjustments, and in July 2009 we completed the sale of our E. Texas gas gathering system for $18.4 million.

At December 31, 2010 we had a working capital deficit of approximately $127.8 million. We generally maintain a working capital deficit because we use excess cash to reduce borrowings under our Credit Agreement. Our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

Credit Ratings

Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate our Senior Notes and have assigned us a credit rating. We do not have any provisions that are linked to our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our currently outstanding debt. However, our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Historical Cash Flows

Cash flows provided by operating activities are primarily affected by the price of crude oil and natural gas, production volumes, and changes in working capital. The increase in net cash provided by operating activities of $155 million in 2010 compared to 2009 is primarily due to higher realized commodity sales prices in 2010 compared to 2009 and a 9% increase in production in 2010 compared to 2009. The decrease in net cash provided by operating activities of $197 million in 2009 compared to 2008 is primarily due to lower realized commodity sales prices in 2009 compared to 2008.

Cash flows used by investing activities are primarily comprised of development, exploitation and acquisition of oil and gas properties net of dispositions of oil and gas properties. The increase in net cash used in investing activity of $634 million in 2010 compared to 2009 is due to an increase in development expenditures and an increase in acquisition activities in 2010. The decrease in net cash used in investing activities of $1.0 billion in 2009 compared to 2008 is due to the 2008 E. Texas acquisition, a decrease in development expenditures in 2009 and the 2009 sale of our DJ assets.

Net cash provided by financing activities included net proceeds of $224 million from the issuance of 8 million shares of our Class A common stock and $300 million aggregate principal amount of our 6.25% senior notes due 2020, offset by debt issuance costs of $15 million and net repayment of our outstanding borrowings under our Credit Agreement and Line of Credit of $197 million. Net cash used in financing activities in 2009 included $450 million of 10.25% senior notes due 2014 for net proceeds of $435 million after consideration of related discounts and premiums, offset by $24 million of debt issuance costs and the net repayment of our outstanding borrowings under our Credit Agreement and Line of Credit of $585 million. Net cash provided by financing activities in 2008 included net borrowings under our Credit Agreement and Line of Credit of $698 million, offset by dividends paid of $13 million and debt issuance costs of $11 million.

Capital Expenditures

The following is a summary of the drilling and development capital expenditures incurred in the years ended December 31 (in thousands):

Asset Team	2010	2009	2008
S. Midway	$ 35,000	$ 24,000	$ 55,000
N. Midway	67,000	32,000	70,000
Permian	42,000	—	—
Uinta	50,000	6,000	59,000
E. Texas	71,000	47,000	66,000
Piceance	45,000	26,000	130,000
DJ and other	—	—	18,000
Total	$ 310,000	$ 135,000	$ 398,000

We continually evaluate our capital needs and compare them to our capital resources. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. We expect our 2011 capital budget to be between $375 million and $425 million assuming an average commodity price of $75 WTI, which we expect to fund with net cash provided by our operating activities. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we may adjust our capital budget accordingly or adjust borrowings under our Credit Agreement, as needed. Approximately 90% of our 2011 capital expenditure budget is directed towards our oil assets, targeting oil production growth of approximately 20%.

Although we have no specific budget for property acquisitions in 2011, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should attractive acquisition opportunities be presented, we will be able to finance additional capital expenditures with cash flows from operating activities, borrowings under our Credit Agreement, issuances of additional debt or equity, or agreements with industry partners. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs, dividend distributions and debt repayments; while complying with our debt covenants and meeting any other obligations that may arise from our oil and gas operations.

Contractual Obligations

Our contractual obligations as of December 31, 2010 are as follows (in millions):

	Total	2011	2012	2013	2014	2015	Thereafter
Long-term debt and interest(1)	$ 1,594.9	$ 91.6	$ 86.3	$ 86.3	$ 509.4	$ 209.6	$ 611.7
Asset retirement obligations(2)	53.4	2.3	2.1	2.0	2.0	2.0	43.0
Operating leases(3)	14.4	2.7	2.7	2.7	2.6	2.3	1.4
Drilling rig commitments(4)	2.0	2.0	—	—	—	—	—
Firm natural gas transportation contracts(5)	278.1	24.9	29.3	30.1	32.1	32.1	129.6
Derivative liability(6)	118.4	84.9	24.1	9.4	—	—	—
Total	$ 2,061.2	$ 208.4	$ 144.5	$ 130.5	$ 546.1	$ 246.0	$ 785.7

(1) Long-term debt consists of our 8.25% Senior subordinated notes due 2016, 10.25% Senior notes due 2014, 6.75% Senior notes due 2020 and outstanding debt under our Credit Agreement, and

assumes no principal repayment until the due date of the instruments. Cash interest expense on the Credit Agreement is estimated assuming no principal repayment until the instrument due date and is estimated at a constant interest rate of 2.02%.

(2) Asset retirement obligations represent the estimated fair value at December 31, 2010 of our obligations with respect to the retirement/abandonment of our oil and gas properties. Each reporting period the liability is accreted to its then present value. The ultimate settlement amount and the timing of the settlement of such obligations are unknown because they are subject to, among other things, federal, state, local, and tribal regulation and economic factors.

(3) Operating leases relate primarily to obligations associated with our office facilities, equipment, vehicles and aircraft.

(4) We currently have two drilling rigs under contract. Both contracts expire in 2011. All other rigs currently performing work for us are on a well-by-well basis and, therefore, can be released without penalty at the conclusion of drilling on the current well. These latter types of drilling obligations have not been included in the table above.

(5) We enter into certain firm commitments to transport natural gas production to market and to transport natural gas for use in our cogeneration and conventional steam generation facilities. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity is used or not. These commitments include firm transportation agreements with El Paso Corporation for an average 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. The commitments are based on the expectation that the project will proceed and transportation will begin in mid-2011.

(6) Derivative liabilities represent the fair value for derivatives presented as liabilities in our Balance Sheets as of December 31, 2010. Consistent with the presentation in our Balance Sheets, only derivative assets that are offset under a legal right of offset are included in this table. The ultimate settlement amounts of our derivative liabilities are unknown because they are subject to continuing market fluctuations.

Based on current oil and natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with amounts available under our credit agreement, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as disclosure of contingent assets and liabilities at the date of our financial statements. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note 1 to our Financial Statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Successful Efforts Method of Accounting. We account for our oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs 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. Exploratory wells that discover potentially economic reserves that are 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 as long as the additional exploratory work is under way or firmly planned. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that economic proved reserves have been discovered may take considerable time and judgment. The evaluation of oil and gas leasehold acquisition costs included in unproved properties requires management's judgment to estimate the fair value of such properties.

Capitalized Interest. Acquisition costs of proved undeveloped and unproved properties qualify for interest capitalization during a period if interest cost is incurred and activities necessary to bring the properties into a productive state are in progress. As wells are drilled in a field with proved undeveloped or unproved reserves, a portion of the acquisition costs are either re-designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, we determine the amount of the acquisition cost to re-designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

Oil and Gas Reserves. Oil and gas reserves include proved reserves, which are those quantities of oil and natural 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. Our oil and gas reserves are based on estimates prepared by independent engineering consultants. Reserve engineering is a process that requires judgment in the evaluation of all available geological, geophysical, engineering and economic data. Projected future production rates, the timing of future capital expenditures as well as changes in commodity prices, may significantly impact estimated reserve quantities. Depreciation, depletion and amortization (DD&A) expense is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. These estimates are subject to change as additional information and technologies become available. Accordingly, oil and natural gas quantities ultimately recovered and the timing of production may be substantially different than projected. Reduction in reserve estimates may result in increased DD&A expense. Changes in reserve estimates are applied on a prospective basis. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher costs fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties. We review our proved natural gas and oil properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our gas and oil properties and compare these undiscounted future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the natural gas and oil properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk associated with realizing the projected cash flows.

Unproved oil and gas properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage and allocate capital. When we have allocated fair values to a significant unproved property (probable reserves) as the result of a business combination or other purchase of proved and unproved properties, we use a future cash flow analysis to assess the property for impairment. *Probable reserves* are defined in SEC Regulation S-X, Rule 4-10(a)(18) as those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

Purchase Price Allocations. We occasionally acquire assets and assume liabilities in transactions accounted for as business combinations. In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. Any excess of amounts assigned to assets and liabilities over the purchase price is recorded as a gain on bargain purchase. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, we must prepare estimates. To estimate the fair values of these properties, we prepare estimates of crude oil and natural gas reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net earnings for the period in which the impairment is recorded.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We also enter 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 accumulated other comprehensive loss 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, have 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 and any ineffective portion of the derivative instrument's change in fair value is recognized immediately in earnings. The estimated fair value of our 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, and time to maturity and credit risk. The values we report in our financial statements changes as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. Effective January 1, 2010, we elected to de-designate all of our 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.

Income Taxes and Uncertain Tax Positions. Income taxes are provided for the tax effects of transactions reported in the financial statements and consists of income taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are also recognized for income tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted income tax rates to the differences between the financial statements and income tax reporting. We routinely assess the realizability of our deferred income tax assets, and a valuation allowance is recognized if it is determined that deferred income tax assets may not be fully utilized in future periods. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). There can be no assurance that facts and circumstances will not materially change and require us to establish deferred income tax asset valuation allowances in a future period. We are subject to taxation in many jurisdictions, and the calculation of our income tax liabilities involves dealing with uncertainties in the application of complex income tax laws and regulations in various taxing jurisdictions. We recognize certain income tax positions that meet a more-likely-than not recognition threshold. If we ultimately determine that the payment of these liabilities will be unnecessary, we will reverse the liability and recognize an income tax benefit during the period in which we determine the liability no longer applies.

Asset Retirement Obligations. Our asset retirement obligations (AROs) consist primarily of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of the ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted-risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net earnings as accretion expense. The related capital cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas field.

Environmental Remediation Liability. We review, on a quarterly basis, our estimates of costs of the cleanup of various sites including sites in which governmental agencies have designated us as a potentially responsible party. When it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of remediation can be determined, the applicable amount is accrued. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is an estimation process that includes the judgment of management. In many cases, management's judgment is based on the advice and opinions of legal counsel and other advisers, and the interpretation of laws and regulations, which can be interpreted differently by regulators or courts of law. Our experience and the experience of other companies in dealing with similar matters influence the decision of management as to how it intends to respond to a particular matter. A change in estimate could impact our oil and gas operating costs and the liability, if applicable, recorded on our Balance Sheet.

Electricity Cost Allocation. Our investment in our cogeneration facilities has been for the express purpose of lowering steam costs in our California heavy oil operations and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam and use natural gas as fuel. We allocate steam costs to our oil and gas operating costs based on the conversion efficiency (of fuel to electricity and steam) 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.

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, requires new disclosures, and clarifies existing disclosures. The ASU is effective for interim and annual reporting periods beginning after December 15, 2009 and was adopted on January 1, 2010, 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. The adoption of these disclosure requirements is not expected to have an impact on our financial position, results of operations, or operating cash flows.

Reconciliation of Non-GAAP Measures

Discretionary Cash Flow. In addition to reporting cash provided by operating activities as defined under GAAP, we present discretionary cash flow, which is a non-GAAP liquidity measure. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items. Management uses discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. The following table provides a reconciliation of cash provided by operating activities, the most directly comparable GAAP measure, to adjusted discretionary cash flow for the period presented.

	Years Ended December 31:		
(in millions)	**2010**	**2009**	**2008**
Net cash provided by operating activities	$ 367.2	$ 212.6	$ 409.6
Add back: Net increase (decrease) in current assets	(12.5)	10.1	(10.3)
Add back: Net decrease (increase) in current liabilities including book overdraft	(12.7)	33.6	(3.1)
Add back: Unwind interest swap payments	10.8	—	—
Add back: Recovery of Flying J bad debt	38.5	—	(38.5)
Discretionary cash flow	$ 391.3	$ 256.3	$ 357.7

Operating Margin per BOE. In addition to reporting net earnings as defined under GAAP, we present operating margin, which is a non-GAAP profitability measure. Operating margin per barrel consists of oil and gas revenues less oil and gas operating expenses and production taxes divided by the total barrels sold during the period. Management uses operating margin per barrel as a measure of profitability and believes it provides useful information to investors because it relates our oil and gas revenue and oil and gas operating expenses to our total units of production providing a gross margin per unit of production. Using this measure, investors can evaluate how profitability varies on a per unit basis each period.

	Years Ended December 31:		
(per BOE)	**2010**	**2009**	**2008**
Average sales price including cash derivative settlements	$ 53.84	$ 46.02	$ 61.85
Average operating costs—oil and gas production	15.95	14.66	17.99
Average production taxes	1.93	1.70	2.56
Average operating margin	$ 35.96	$ 29.66	$ 41.30

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our primary market risk is oil and gas commodity prices. Historically the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. We use various derivative instruments to manage our exposure to commodity price risk. All derivative instruments are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value, both realized and unrealized, are recorded as unrealized gains or losses in Realized and unrealized (loss) gain on derivatives, net in the Statements of Income. Cash flows are only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty. The derivative instruments we have in place are not classified as hedges for accounting purposes. See Notes 8 and 9 to the Financial Statements.

Currently, our derivatives are in the form of swaps and collars. However, we may use a variety of derivative instruments in the future to hedge WTI or other index prices. A two-way collar is a combination of options, a sold call and purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options, a sold call, a purchased put and a sold put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. We utilize costless collars which are options positions by which the proceeds from the sale of the call option fund the purchase of a put option. In 2010, a $10 increase in oil prices would have increased our annual operating cash flows by approximately $27 million, and a $10 decrease in oil prices would have decreased our annual operating cash flows by approximately $31 million. The combined impact of our natural gas consumption to generate steam in California and financial hedges reduces our exposure to changes in natural gas prices. In 2010, a $1 change in natural gas prices would have impacted annual operating cash flows by approximately $6 million.

The following table summarizes our commodity hedge positions as of December 31, 2010:

Term	Average Barrels Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Collars		
Full year 2011	270	$80.00/$90.00
Full year 2011	1,000	$55.20/$70.00
Full year 2011	1,000	$55.00/$70.50
Full year 2011	1,000	$55.00/$68.65
Full year 2011	1,000	$55.00/$68.00
Full year 2011	1,000	$55.00/$71.20
Full year 2011	1,000	$60.00/$76.00
Full year 2011	1,000	$60.00/$81.25
Full year 2011	500	$75.00/$101.15
Full year 2011	500	$75.00/$100.75
Full year 2011	1,000	$75.00/$91.25
Full year 2012	1,000	$63.00/$82.60
Full year 2012	1,000	$63.00/$83.50
Full year 2012	1,000	$70.00/$93.00
Full year 2012	500	$75.00/$106.00
Full year 2012	500	$75.00/$105.00
Full year 2012	1,000	$75.00/$95.00
Crude Oil Sales (NYMEX WTI) Swaps		
Full year 2011	500	$57.36
Full year 2011	500	$57.40
Full year 2011	500	$57.50
Full year 2011	250	$61.80
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2011	5,000	$6.89
Full year 2011	5,000	$5.50
Full year 2012	5,000	$7.16
Full year 2012	5,000	$5.75
Natural Gas Sales (NYMEX HH) Collars		
Full year 2011	5,000	$6.00/$7.25
Full year 2012	5,000	$6.00/$7.70

Term	Average MMBtu Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2011	500	$65.00/$85.00/$97.25
Full year 2011	1,000	$70.00/$87.00/$105.00
Full year 2011	1,000	$55.00/$75.00/$91.63
Full year 2011	1,000	$60.00/$80.00/$101.00
Full year 2011	1,000	$70.00/$88.15/$100.00
Full year 2011	1,000	$70.00/$86.85/$100.00
Full year 2011	1,000	$69.70/$85.00/$100.00
Full year 2011	500	$70.00/$85.00/$94.68
Full year 2012	1,000	$65.00/$85.00/$97.25
Full year 2012	1,000	$70.00/$87.00/$105.00
Full year 2012	1,000	$70.00/$88.00/$106.00
Full year 2012	1,000	$60.00/$80.00/$96.92
Full year 2012	1,000	$60.00/$80.00/$120.00
Full year 2012	1,000	$70.00/$88.15/$100.00
Full year 2012	1,000	$70.00/$86.85/$100.00
Full year 2012	1,000	$69.70/$85.00/$100.00
Full year 2012	1,000	$70.00/$87.00/$108.50
Full year 2013	1,000	$65.00/$85.00/$97.25
Full year 2013	1,000	$70.00/$87.00/$105.00
Full year 2013	1,000	$70.00/$88.00/$106.00
Full year 2013	1,000	$60.00/$80.00/$103.30
Full year 2013	1,000	$70.00/$88.15/$100.00
Full year 2013	1,000	$70.00/$86.85/$100.00
Full year 2013	1,000	$69.70/$85.00/$100.00
Full year 2013	1,000	$70.00/$87.00/$108.50
Natural Gas Sales (NYMEX HH to NGPL-Tex OK) Basis Swaps		
Full year 2011	2,500	$0.460
Full year 2012	2,500	$0.440
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2011	2,500	$0.325
Full year 2012	2,500	$0.320

Based on NYMEX futures prices as of December 31, 2010 (WTI $93.45; HH $4.72) for the term of our derivatives we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas derivatives in place as follows:

	12/31/10 NYMEX Futures	Impact of percent change in futures prices on pre-tax future cash (payments) and receipts			
		-40%	-20%	+20%	+40%
Average WTI Futures Price (2011 - 2013)	$ 93.45	$ 56.07	$ 74.76	$ 112.14	$ 130.83
Average HH Futures Price (2011 - 2012)	4.72	2.83	3.78	5.67	6.61
Crude Oil gain/(loss) (in millions)	$ (89.6)	$ 193.4	$ 66.4	$ (285.1)	$ (553.7)
Natural Gas gain/(loss) (in millions)	22.6	50.2	36.4	8.9	(2.8)
Total	$ (67.0)	$ 243.6	$ 102.8	$ (276.2)	$ (556.5)
Net pre-tax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2011 (WTI $93.45; HH $4.44)	$ (68.8)	$ 84.3	$ 20.6	$ (178.2)	$ (302.3)
2012 (WTI $93.95; HH $5.01)	1.8	108.1	48.5	(71.6)	(173.5)
2013 (WTI $92.95)	—	51.2	33.7	(26.4)	(80.7)
Total	$ (67.0)	$ 243.6	$ 102.8	$ (276.2)	$ (556.5)

Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our Credit Agreement. Our Credit Agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to 12 months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the Credit Agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt. At December 31, 2010, our outstanding principal balance under our Credit Agreement was $170.0 million and the weighted average interest rate on the outstanding principal balance was 2.0%. At December 31, 2010, the carrying amount approximated fair market value. Assuming a constant debt level of $1.1 billion, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $1.1 million over a 12-month time period.

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.

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, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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 8 to the financial statements, the Company discontinued hedge accounting effective January 1, 2010.

As discussed in Note 16 to the financial statements, the Company has restated its 2009 and 2008 financial statements to correct an error.

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
March 1, 2011

BERRY PETROLEUM COMPANY

Balance Sheets

December 31, 2010 and 2009

(In Thousands, Except Share Information)

	2010	2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 278	$ 5,311
Short-term investments	65	66
Accounts receivable, net of allowance for doubtful accounts of $0 and $38,508, respectively	93,406	74,337
Deferred income taxes	32,342	5,623
Derivative instruments	2,742	11,527
Prepaid expenses and other	14,033	6,612
Total current assets	142,866	103,476
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,655,792	2,106,385
Derivative instruments	2,054	735
Other assets	37,904	29,539
	$ 2,838,616	$ 2,240,135
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 106,459	$ 63,096
Revenue and royalties payable	37,812	25,878
Accrued liabilities	36,234	29,320
Line of credit	5,300	—
Derivative instruments	84,846	33,843
Total current liabilities	270,651	152,137
Long-term liabilities:		
Deferred income taxes	329,207	237,161
Senior secured revolving credit facility	170,000	372,000
$8^{1}/4$% Senior subordinated notes due 2016	200,000	200,000
$10^{1}/4$% Senior notes due 2014, net of unamortized discount of $11,035 and $13,456, respectively	438,965	436,544
$6^{3}/4$% Senior notes due 2020	300,000	—
Asset retirement obligations	53,443	43,487
Derivative instruments	33,526	75,836
Other long-term liabilities	18,271	19,711
	1,543,412	1,384,739
Commitments and contingencies (Note 10)		
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; 51,426,232 and 42,952,499 shares issued and outstanding, respectively	514	430
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	327,369	89,068
Accumulated other comprehensive loss	(43,806)	(60,372)
Retained earnings	740,458	674,115
Total shareholders' equity	1,024,553	703,259
	$ 2,838,616	$ 2,240,135

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

BERRY PETROLEUM COMPANY

Statements of Income

Years ended December 31, 2010, 2009 and 2008

(In Thousands, Except Per Share Data)

	2010	Restated (Note 16) 2009	2008
REVENUES			
Sales of oil and gas	$ 619,608	$ 500,532	$ 647,357
Sales of electricity	34,740	36,065	63,525
Gas marketing	22,162	22,806	35,750
Realized and unrealized (loss) gain on derivatives, net	(31,847)	(7,756)	(358)
Settlement of Flying J bankruptcy claim	21,992	—	—
Gain (loss) on sale of assets	—	826	(1,297)
Interest and other income, net	3,300	1,810	3,504
	669,955	554,283	748,481
EXPENSES			
Operating costs—oil and gas production	190,218	156,612	188,758
Operating costs—electricity generation	31,295	31,400	54,891
Production taxes	22,999	18,144	26,876
Depreciation, depletion & amortization—oil and gas production	179,432	139,919	125,595
Depreciation, depletion & amortization—electricity generation	3,225	3,681	2,812
Gas marketing	19,896	21,231	32,072
General and administrative	52,846	49,237	54,279
Interest	66,541	49,923	23,797
Extinguishment of debt	573	10,823	—
Transaction costs on acquisitions	2,635	—	—
Dry hole, abandonment, impairment and exploration	2,311	5,425	10,543
Bad debt (recovery) expense	(38,508)	—	38,665
	533,463	486,395	558,288
Earnings from continuing operations before income taxes	136,492	67,888	190,193
Provision for income taxes	53,968	20,664	69,616
Earnings from continuing operations	82,524	47,224	120,577
Earnings from discontinued operations, net of income taxes	—	6,806	12,952
Net earnings	$ 82,524	$ 54,030	$ 133,529
Net earnings from continuing operations per share, Basic	1.54	1.03	2.67
Net earnings from discontinued operations per share, Basic	—	0.15	0.29
Net earnings per share, Basic	$ 1.54	$ 1.18	$ 2.96
Net earnings from continuing operations per share, Diluted	1.52	1.02	2.64
Net earnings from discontinued operations per share, Diluted	—	0.15	0.28
Net earnings per share, Diluted	$ 1.52	$ 1.17	$ 2.92

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

BERRY PETROLEUM COMPANY

Statements of Shareholders' Equity

Years Ended December 31, 2010, 2009 and 2008

(In Thousands)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balances at January 1, 2008	$ 425	$ 18	$ 66,590	$ 513,645	$ (120,704)	$ 459,974
Stock options and restricted stock issued	2	—	2,813	—	—	2,815
Stock based compensation	—	—	9,313	—	—	9,313
Tax effect of stock option exercises	—	—	937	—	—	937
Dividends ($0.30 per share)	—	—	—	(13,425)	—	(13,425)
Comprehensive income:						
Net income	—	—	—	133,529	—	133,529
Effect of derivative instruments, net of taxes	—	—	—	—	234,401	234,401
Total comprehensive income	—	—	—	—	—	367,930
Balances at December 31, 2008	427	18	79,653	633,749	113,697	827,544
Stock options and restricted stock issued	3	—	890	—	—	893
Stock based compensation	—	—	8,623	—	—	8,623
Tax effect of stock option exercises	—	—	(98)	—	—	(98)
Dividends ($0.30 per share)	—	—	—	(13,664)	—	(13,664)
Comprehensive loss:						
Net income	—	—	—	54,030	—	54,030
Effect of derivative instruments, net of taxes	—	—	—	—	(174,069)	(174,069)
Total comprehensive loss	—	—	—	—	—	(120,039)
Balances at December 31, 2009	430	18	89,068	674,115	(60,372)	703,259
Issuance of stock	80	—	224,233	—	—	224,313
Stock options and restricted stock issued	4	—	4,398	—	—	4,402
Stock based compensation	—	—	9,386	—	—	9,386
Tax effect of stock option exercises	—	—	284	—	—	284
Dividends ($0.30 per share)	—	—	—	(16,181)	—	(16,181)
Comprehensive income:						
Net income	—	—	—	82,524	—	82,524
OCI amortization of de-designated hedges, net of taxes	—	—	—	—	16,566	16,566
Total comprehensive income	—	—	—	—	—	99,090
Balances at December 31, 2010	$ 514	$ 18	$ 327,369	$ 740,458	$ (43,806)	$ 1,024,553

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

BERRY PETROLEUM COMPANY

Statements of Cash Flows

Years Ended December 31, 2010, 2009 and 2008

(In Thousands)

	2010	2009	2008
Cash flows from operating activities:			
Net earnings	$ 82,524	$ 54,030	$ 133,529
Depreciation, depletion and amortization	182,657	145,788	141,049
Extinguishment of debt	573	10,823	—
Amortization of debt issuance costs and net discount	8,481	6,827	1,774
Dry hole and impairment	1,478	14,859	9,932
Derivatives	42,609	247	(108)
Stock-based compensation expense	9,386	8,626	9,313
Deferred income taxes	54,698	19,998	67,982
Loss on sale of asset	—	79	1,297
Other, net	(12)	(4,016)	(2,530)
Cash paid for abandonment	(1,832)	(1,030)	(4,607)
Allowance for bad debt	(38,508)	—	38,511
Change in book overdraft	528	(16,018)	23,984
Changes in operating assets and liabilities:			
Accounts receivable	20,055	(11,816)	14,295
Inventories, prepaid expenses, and other current assets	(7,553)	1,761	(4,014)
Accounts payable and revenue and royalties payable	5,273	(49,119)	(7,881)
Accrued interest and other accrued liabilities	6,880	31,537	(12,957)
Net cash provided by operating activities	367,237	212,576	409,569
Cash flows from investing activities:			
Exploration and development of oil and gas properties	(310,139)	(134,946)	(397,601)
Property acquisitions	(334,409)	(13,497)	(667,996)
Capitalized interest	(28,321)	(30,107)	(23,209)
Proceeds from sale of assets	—	139,796	2,037
Net cash used in investing activities	(672,869)	(38,754)	(1,086,769)
Cash flows from financing activities:			
Proceeds from issuances on line of credit	316,000	387,700	404,000
Payments on line of credit	(310,700)	(413,000)	(393,000)
Proceeds from issuance of 10.25% senior notes	—	434,962	—
Proceeds from issuance of 6.75% senior notes	300,000	—	—
Proceeds from long-term borrowings under credit facility	363,000	655,300	1,708,700
Repayments of long-term borrowings under credit facility	(565,000)	(1,215,100)	(1,021,900)
Debt issuance costs	(15,173)	(23,955)	(11,002)
Proceeds from issuance of stock	224,313	—	—
Financing obligation	(346)	18,214	—
Dividends paid	(16,181)	(13,664)	(13,425)
Proceeds from stock option exercises	4,402	890	2,813
Excess tax (expense) benefit	284	(98)	938
Net cash provided by (used in) financing activities	300,599	(168,751)	677,124
Net (decrease) increase in cash and cash equivalents	(5,033)	5,071	(76)
Cash and cash equivalents at beginning of year	5,311	240	316
Cash and cash equivalents at end of year	$ 278	$ 5,311	$ 240
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest	$ 40,773	$ 36,854	$ 15,708
Income taxes (refunded) paid	(285)	8,769	13,290
Noncash Investing Activities:			
Change in accrued capital expenditures	$ 46,036	$ 32,690	$ 20,938
Increase in asset retirement obligations	3,721	1,407	6,658

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

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, exploitation and acquisition 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 generate electricity for sale.

Basis of Presentation

These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). In addition, the Company has restated its historical financial statements for the years ended December 31, 2009 and 2008. See Notes 15 and 16 to the Financial Statements.

Certain amounts in prior years' financial statements have been reclassified to conform to the 2010 financial statement presentation.

Assumptions, Judgments, and Estimates

In the course of preparing the financial statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts previously established.

The more significant areas requiring the use of assumptions, judgments, and estimates include: (1) oil and natural gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) income taxes; (7) valuation of derivative instruments; and (8) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates.

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, 2010 and 2009 is $16.3 million and $15.7 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 purchasers and from 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.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

1. Summary of Significant Accounting Policies (Continued)

Allowance for Doubtful Accounts and Bad Debt Recovery

The Company recognized $38.5 million in bad debt expense in the year ended December 31, 2008 related to the Flying J bankruptcy. On July 6, 2010, the Joint Plan of Reorganization of Flying J was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J regarding the resolution of the Company's claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, Flying J agreed that the total amount owed to the Company by Flying J was $60.5 million and, as a result, the Company received $60.5 million in cash on July 23, 2010. In the quarter ended September 30, 2010, the Company recorded a settlement of the Company's Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

Discontinued Operations

In 2009, the Company sold its DJ assets, the results of operations of which are reported as discontinued operations in the 2009 Statements of Income. See Note 2 to the Financial Statements.

Income Taxes and Uncertain Income Tax Positions

The Company recognizes deferred income tax liabilities and assets for the expected future income tax consequences of temporary differences between financial accounting bases and income tax bases of assets and liabilities. Deferred income taxes are measured by applying currently enacted income tax rates. The Company accounts for uncertainty in income taxes for income tax positions taken or expected to be taken in an income tax return. Only income tax positions that meet the more-likely-than-not recognition threshold will be recognized.

Derivative Instruments

The Company enters into derivative contracts, primarily swaps and collars, to manage its exposure to commodity price risk. All derivative instruments, other than those that meet the "normal purchase normal sales" exclusion, are recorded on the balance sheet as either an asset or liability measured at fair value. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. The Company is required to formally document, at the inception of a hedge, the hedging relationship and the risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the method that will be used to assess effectiveness and the method that will be used to measure hedge ineffectiveness of derivative instruments that receive hedge accounting treatment. Effective January 1, 2010, the Company elected to discontinue all hedge accounting prospectively. As a result, subsequent to December 31, 2009, the Company records all derivative instruments as either assets or liabilities at fair value and recognizes all gains and losses from changes in derivative fair values immediately in earnings rather than deferring any such amounts in AOCL. See Note 8 to the Financial Statements. Cash flows from derivatives used to manage commodity price risk are classified in operating activities along with the cash flows of the underlying derivative transactions. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract. The Company uses these agreements to manage and reduce

1. Summary of Significant Accounting Policies (Continued)

its potential counterparty credit risk. The Company does not enter into derivative instruments for speculative or trading purposes.

Oil and Gas Properties, Buildings and Equipment

In January 2010, the Financial Accounting Standards Board ("FASB") issued oil and gas reserve estimation and disclosure authoritative accounting guidance effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the Securities and Exchange Commission's ("SEC") final rule, "*Modernization of Oil and Gas Reporting*", which was also effective for annual reports for fiscal years ending on or after December 31, 2009. These rules, among other things, changed pricing used to estimate oil and gas reserves, broadened the types of technologies that a company may use to establish oil and gas reserves estimates, and broadened the definition of oil and gas producing activities. Accordingly, the Company adopted both the FASB's authoritative accounting guidance and the SEC's rule as of December 31, 2009.

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs 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 finds 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.

The provision for depletion of oil and gas properties is calculated on a field-by-field basis using the unit-of-production method. If the estimates of total proved or proved developed reserves decline, the rate at which the Company records depreciation, depletion and amortization (DD&A) expense increases, which in turn reduces net earnings. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. The Company is unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of its development program, as well as future economic conditions. Changes in reserves are applied on a prospective basis.

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.

Acquisition costs of proved undeveloped and unproved properties qualify for interest capitalization during a period if interest cost is incurred and activities necessary to bring the properties into a productive state are in progress. As wells are drilled in a field with proved undeveloped reserves or unproved reserves, a portion of the acquisition costs are either re-designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, the Company determines the

1. Summary of Significant Accounting Policies (Continued)

amount of the acquisition cost to re-designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected future cash flows of its oil and natural gas properties and compares these undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk associated with realizing the projected cash flows.

Unproved oil and natural gas properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage and allocate capital. When the Company has allocated fair values to significant unproved property (probable reserves) as the result of a business combination or other purchase of proved and unproved properties, it uses a future cash flow analysis to assess the property for impairment. *Probable reserves* are defined in SEC Regulation S-X, Rule 4-10(a)(18) as those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

Asset Retirement Obligations

Asset retirement obligations (ARO) relate to future costs associated with plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The fair value of a liability for an ARO 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

The components of accrued liabilities for the years ended 2010 and 2009 are as follows:

(in thousands)	2010	2009
Property taxes	$ 11,245	$ 8,187
Accrued interest	10,074	6,904
Accrued payroll	10,225	8,189
Other accrued liabilities	4,690	6,040
Total accrued liabilities	$ 36,234	$ 29,320

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

1. Summary of Significant Accounting Policies (Continued)

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 also derived from gas marketing sales, which represent excess capacity on the Rockies Express pipeline used by the Company to market natural gas for its working interest partners.

Significant Customers

The Company sells oil, natural gas and natural gas liquids to various types of customers, including pipelines, refineries and other oil and gas 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 of its products, 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 Company's crude oil sales customer in Utah could impact the marketability of a portion of the Company's Utah crude oil volumes.

In 2010, sales to Shell Trading (US) Company and ExxonMobil Oil Corporation accounted for approximately 44% and 14%, respectively, of the Company's revenue. 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.

Concentrations of Market Risk

The results of the Company's oil and natural gas operations are impacted by the market prices of oil and natural gas. The availability of a ready market for crude oil, natural gas and liquid products in the future depends 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 2010 and 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 bankruptcy of BWOC. See "Allowance for Doubtful Accounts and Bad Debt Recovery" above. The Company recovered $60.5 million in 2010, as described above. As of December 31, 2010, the Company has over 88% of its California oil production under contract with Shell Trading (US) Company and ExxonMobil Oil Corporation through March and November 2011, respectively.

The Company places its temporary cash investments with high quality financial institutions and does not limit the amount of credit exposure to any one financial institution. For the three years ended December 31, 2010, the Company has not incurred losses related to these investments.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

1. Summary of Significant Accounting Policies (Continued)

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, which 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. A portion of the capital costs of the cogeneration facilities is allocated to DD&A-oil and gas production. Electricity used in oil and gas operations is allocated at cost. Electricity consumption included in oil and gas operating costs for the years ended December 31, 2010, 2009 and 2008 was $2.8 million, $2.8 million and $5.8 million, respectively.

Transportation Costs

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 $16.4 million, $16.9 million and $10.0 million for 2010, 2009 and 2008, respectively. Costs for transporting natural gas used in electricity generation were $4.7 million, $2.8 million and $7.2 million for 2010, 2009 and 2008, respectively; a portion of these costs are allocated to Operating costs—oil and gas production, as described above, and the remainder are included in Operating costs—electricity production.

Stock-Based Compensation

The Company recognizes the grant date fair value of stock options and other stock based compensation issued in the Statements 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 Per Share

Basic earnings per common share is calculated by dividing adjusted earnings available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing earnings available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share accordingly.

The two-class method of computing earnings per share is required for entities that have participating securities. The two class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Unvested restricted stock issued prior to January 1, 2010, under the Company's equity incentive plans, has the right to receive non-forfeitable dividends, participating on an equal basis with common stock. Unvested restricted stock issued subsequent to

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

1. Summary of Significant Accounting Policies (Continued)

January 1, 2010, under the Company's stock incentive plans, no longer has the right to receive non-forfeitable dividends.

Equity Method Investments

The Company owns interests in two entities that gather and transport natural gas in the Company's Lake Canyon and Brundage Canyon fields. The Company owns less than a 50% interest in both of these entities and such 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 Sheets.

Comprehensive Earnings (Loss)

Comprehensive earnings (loss) is a term used to refer to net earnings plus other comprehensive earnings (loss). Other comprehensive earnings (loss) is comprised of revenues, expenses, gains, and losses that under generally accepted accounting principles are reported as separate components of shareholders' equity instead of net earnings (loss). The components of other comprehensive earnings (loss) were as follows:

	For the Year Ended December 31,		
(in thousands)	2010	2009	2008
Net earnings	$ 82,524	$ 54,030	$ 133,529
Unrealized gains (losses) on derivatives, net of income taxes of $0, ($79,240), and $96,546, respectively	—	(129,287)	157,522
Reclassification of realized (gains) losses on derivatives included in net income, net of income taxes of $10,153, ($27,447), and $47,119, respectively	16,566	(44,782)	76,879
Comprehensive earnings (loss)	$ 99,090	$ (120,039)	$ 367,930

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the production, development, exploitation and acquisition of oil and natural gas, and all of the Company's operations are conducted in the continental United States. Consequently, the Company currently reports as a single industry segment.

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, requires new disclosures, and clarifies existing disclosures. The ASU is effective for interim and annual reporting periods beginning after December 15, 2009 and was adopted by the Company on January 1, 2010, except for the disclosures about purchases, sales, issuances, and settlements in the rollforward activity in Level 3 fair value measurements, which are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. The adoption of these disclosure requirements is not expected to have an impact on the Company's financial position or results of operations.

2. Acquisitions and Divestitures

In March, April, and November 2010, the Company completed three acquisitions of producing properties located in the Wolfberry trend in the Permian for an aggregate purchase price of approximately $328 million, subject to usual and customary post-closing adjustments (the Permian Acquisitions). The Permian Acquisitions were financed with proceeds from the issuance of the Company's Class A Common Stock in January 2010, cash generated from operations and proceeds from the November 2010 issuance of the Company's 6.75% senior notes due 2020. As of December 31, 2010, the property acquired in the Permian Acquisitions had total proved reserves of 33.8 MMBOE, of which 88% is crude oil and 13% is proved developed.

The Permian Acquisitions qualify as business combinations and, as such, the Company estimated the fair value of each property as of each acquisition date (the date on which the Company obtained control of the properties). The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs.

The following table summarizes the consideration paid to the sellers and the amounts of the assets acquired and liabilities assumed in the Permian Acquisitions.

	(In thousands)
Consideration paid to sellers:	
Cash consideration	$ 328,059
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed and undeveloped properties	331,592
Other assets acquired	316
Asset retirement obligations	(3,498)
Other liabilities assumed	(351)
Total identifiable net assets	$ 328,059

Acquisition costs for the Permian Acquisitions of $2.6 million have been recorded in the Statements of Income under the caption Transaction costs on acquisitions. Revenues of $28.7 million and earnings of $10.8 million related to the Permian Acquisitions were included in the accompanying Statements of Income for the year ended December 31, 2010.

In March 2009, the Company entered into an agreement to sell its assets in the Denver-Julesburg basin in Colorado (DJ). The transaction closed in April 2009. The Company recorded a pre-tax impairment loss of $9.6 million related to the sale, which is aggregated within the $6.8 million Earnings from discontinued operations, net of income tax, on its Statements of Income for the year ended December 31, 2009.

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BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

2. Acquisitions and Divestitures (Continued)

Earnings from discontinued operations, net of income tax, on the accompanying Statements of Income is comprised of the following (in thousands):

	For the Year Ended December 31,		
		Restated(1)	
	2010	2009	2008
Sales of oil and gas(2)	$ —	$ 11,555	$ 50,620
Realized and unrealized gain on derivatives, net	—	13,786	—
Loss on sale of asset	—	(908)	—
Other revenue	—	623	2,072
Total revenues	—	25,056	52,692
Total expenses(3)	—	15,799	32,263
Earnings from discontinued operations, before income taxes	—	9,257	20,429
Provision for income taxes	—	2,451	7,477
Earnings from discontinued operations, net of income taxes	$ —	$ 6,806	$ 12,952

(1) See Note 16 to the Financial Statements.

(2) Realized gains included in Sales of oil and gas of $6.2 million and $1.9 million were reclassified to discontinued operations for the years ended December 31, 2009 and 2008, respectively.

(3) The Company allocated $0.8 million and $2.4 million of interest to discontinued operations based on the ratio of net assets to the sum of total net assets for the years ended December 31, 2009 and 2008, respectively.

At the time of the DJ asset sale, the Company had designated derivative instruments as cash flow hedges from the forecasted sale of natural gas produced by the DJ assets. As such, all recurring income statement impacts were classified as discontinued operations. Additionally, the Company determined that as a result of the sale of the DJ assets, the forecasted transactions were no longer probable of occurring. Accordingly, the Company discontinued hedge accounting for those hedges and reclassified a gain of $14.3 million from AOCL to the Statements of Income under the caption Earnings from discontinued operations, net of income taxes.

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 Statements of Income under the caption Earnings from discontinued operations, net of income taxes.

In July 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 (E. Texas Acquisition).

The unaudited pro forma results presented below for the year ended December 31, 2008 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 the period 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

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

2. Acquisitions and Divestitures (Continued)

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 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
Pro forma revenue	$ 797,261
Pro forma income from operations	$ 197,196
Pro forma net income	$ 125,917
Pro forma basic earnings per share	$ 2.79
Pro forma diluted earnings per share	$ 2.75

3. Debt

Short-Term Lines of Credit

In 2005, the Company obtained an unsecured uncommitted money market line of credit (Line of Credit). The Line of Credit may be terminated at any time upon written notice by either the Company or the lender with any borrowings outstanding for a maximum of 30 days. In conjunction with the July 15, 2008 amendment to the Company's senior secured revolving credit facility, the Line of Credit was collateralized by oil and natural gas properties. On November 23, 2010, the Company amended the Line of Credit to increase the maximum borrowings from $30 million to $40 million. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1.4%. The $5.3 million of outstanding borrowings under the Line of Credit at December 31, 2010 had a weighted average interest rate of 1.7%.

Senior Secured Revolving Credit Facility

On November 15, 2010, the Company entered into a second amended and restated senior secured revolving credit facility (Credit Agreement), which extended the maturity date to November 13, 2015. The Credit Agreement has a current borrowing base and lender commitments of $875 million, after the reduction to the borrowing base resulting from the Company's issuance of $300 million of 6.75% senior notes due 2020 (2020 Notes). 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 natural 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 Credit Agreement is collateralized by the Company's oil and natural gas properties. The LIBOR and prime rate margins are between 1.75% and 2.75% based on the ratio of credit outstanding to the borrowing base and the annual commitment fee on the unused portion of the Credit Agreement is 0.50%. The Credit Agreement also provides the right for the Company to refinance its 10.25% senior notes due 2014 (2014 Notes) with similar notes or retire the 2014 Notes using available borrowings under the Credit Agreement as long as certain leverage and liquidity tests are met. The deferred loan costs of $8.5 million along with approximately $4.6 million of costs associated with the Company's previous facility are being amortized over the five year term of the

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

3. Debt (Continued)

Credit Agreement. The Company wrote off $0.6 million of deferred loan fees during the fourth quarter of 2010 as a result of the decrease in its borrowing base and for parties who chose not to continue to participate in the Credit Agreement.

The Credit Agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. The Credit Agreement contains restrictive covenants which, among other things, require the Company to maintain the following ratios: (i) an interest coverage ratio, as defined, of 2.75 to 1.0 and (ii) a minimum current ratio, as defined in the Credit Agreement, of 1.0 to 1.0. The Company is currently in compliance with all financial covenants and has complied with all financial covenants for all prior periods.

The total outstanding debt at December 31, 2010, under the Line of Credit and Credit Agreement was $175.3 million and $23.2 million of letters of credit have been issued under the Credit Agreement, leaving $676.5 million in borrowing capacity available.

6.75% Senior Notes Due 2020

On November 1, 2010, the Company issued $300 million in principal amount of its 2020 Notes. Interest is payable in arrears semi-annually in May and November of each year, beginning May 2011. The Company received net proceeds of $294 million, which were used in part to finance a November 2010 acquisition of producing properties in the Permian and the remainder was used to reduce outstanding borrowings under the Credit Agreement. Pursuant to the terms of the Credit Agreement, the issuance of the 2020 Notes automatically reduced its borrowing base by 25 cents per dollar of the 2020 Notes issued. The Company wrote off $0.4 million of deferred loan fees related to the Credit Agreement during the fourth quarter of 2010 as a result of the decrease in its borrowing base. The 2020 Notes are senior unsecured obligations of the Company, which rank effectively junior to all of the Company's existing and any future secured debt, to the extent of the value of the collateral securing that debt, rank equally in right of payment with the 2014 Notes and any future senior unsecured debt, and rank senior in right of payment to the Company's 8.25% senior subordinated notes due 2016 (2016 Sub Notes) and the Company's other future subordinated debt.

The Company may redeem up to 35% of the 2020 Notes at any time prior to November 1, 2013, on one or more occasions, with the proceeds of certain equity offerings at a redemption price of 106.75%. The Company may redeem all or any part of the 2020 Notes at any time beginning on or after November 1, 2015 at the prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued and unpaid interest:

2015	103.375%
2016	102.250%
2017	101.125%
2018 and thereafter	100.000%

The Company may also redeem the 2020 Notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium, plus accrued and unpaid interest to the redemption date.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

3. Debt (Continued)

10.25% Senior Notes Due 2014

On May 27, 2009, the Company issued $325 million in principal amount of its 2014 Notes at 93.546% of par resulting in a discount of $21.0 million. Interest is payable in arrears semi-annually on June 1 and December 1 of each year. The Company received net proceeds of $295 million, which were used to repay the $140 million second lien term loan (discussed below) in full and reduce outstanding borrowings under the Credit Agreement. Pursuant to the terms of the Credit Agreement, the issuance of the 2014 Notes automatically reduced its borrowing base by 25 cents per dollar of 2014 Notes issued. 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 an additional $125 million principal amount of 2014 Notes at 104.75% of par resulting in a premium of $6 million. Interest is payable in arrears semi-annually on June 1 and December 1 of each year. The Company received net proceeds of $129 million, which were used to reduce outstanding borrowings under the Credit Agreement. Pursuant to the terms of the Credit Agreement, the issuance of the 2014 Notes automatically reduced its borrowing base by 25 cents per dollar of notes issued. 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 2014 Notes are treated as a single series of debt securities and are carried on the balance sheet at their combined amortized cost. The 2014 Notes are senior unsecured obligations of the Company, which rank effectively junior to all of the Company's existing and any future secured debt, to the extent of the value of the collateral securing that debt, rank equally in right of payment with the 2020 Notes and any future senior unsecured debt, and rank senior in right of payment to the 2016 Sub Notes and the Company's other future subordinated debt.

The 2014 Notes are redeemable at the Company's option, in whole or in part, at any time at a price equal to 100% of the principal amount of the 2014 Notes plus accrued and unpaid interest, if any, plus a "make-whole" premium.

8.25% Senior Subordinated Notes Due 2016

In 2006, the Company issued $200 million of its 2016 Sub Notes at par for proceeds of $196.0 million. Interest on the 2016 Sub Notes is paid semiannually in May 1 and November 1 of each year. The 2016 Sub Notes rank junior to all of the Company's existing and any future secured debt, to the extent of the value of the collateral securing that debt, junior in right of payment to the 2014 and 2020 Notes and any future senior unsecured debt, and equally in right of payment with any future senior subordinated indebtedness.

The Company may redeem the 2016 Sub Notes at any time beginning on or after November 1, 2011 at the prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued but unpaid interest:

2011	104.125%
2012	102.750%
2013	101.375%
2014 and thereafter	100.000%

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

3. Debt (Continued)

The Company may also redeem the 2016 Sub Notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus accrued and unpaid interest plus a "make-whole" premium.

Second Lien Term Loan

On April 27, 2009, the Company completed a $140 million second lien term loan, 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 2014 Notes, and wrote off $7.2 million in deferred loan fees for the year ended December 31, 2009.

4. Income Taxes

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

	For the Year Ended December 31,		
		Restated(1)	
	2010	2009	2008
Current:			
Federal	$ 363	$ 3,148	$ 2,961
State	1,870	782	5,233
	2,233	3,930	8,194
Deferred:			
Federal	47,709	20,885	56,360
State	4,026	(4,151)	5,062
	51,735	16,734	61,422
Total	$ 53,968	$ 20,664	$ 69,616

(1) See Note 16 to the Financial Statements.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

4. Income Taxes (Continued)

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

	Year Ended December 31, 2010	2009
Deferred income tax assets:		
Federal benefit of state income taxes	$ 6,862	$ 6,064
Credit carryforwards	28,808	27,729
Stock option costs	11,229	11,091
Derivatives	26,838	42,218
Net operating loss	14,545	—
Bad debt expense	—	15,605
Other, net	1,293	1,807
	89,575	104,514
Deferred income tax liabilities:		
Depreciation and depletion	(386,440)	(330,836)
Derivatives	—	(5,216)
	(386,440)	(336,052)
Net deferred income tax liabilities	$ (296,865)	$ (231,538)

At December 31, 2010, the Company's net deferred income tax assets and liabilities were recorded as a current asset of $32.3 million and a long-term liability of $329.2 million. At December 31, 2009, the Company's net deferred income tax assets and liabilities were recorded as a current asset of $5.6 million and a long-term liability of $237.2 million.

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

	For the Year Ended December 31, 2010	Restated(1) 2009	2008
Income tax computed at statutory federal rate	35%	35%	35%
State income taxes, net of federal benefit	4	4	3
Deferred state rate impact	(1)	(5)	(1)
Net impact to uncertain income tax positions	—	(2)	—
Other	2	(2)	—
Effective income tax rate	40%	30%	37%

(1) See Note 16 to the Financial Statements.

The Company has approximately $11 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 2025 and 2016 for federal and California purposes, respectively.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

4. Income Taxes (Continued)

As of December 31, 2010, the Company had a gross liability for uncertain income tax benefits of $5.2 million of which $5.2 million, if recognized, would affect the effective income tax rate. The Company recognizes potential accrued interest and penalties related to unrecognized income tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. The Company had accrued approximately $0.8 million and $0.7 million of interest related to its uncertain income tax positions as of December 31, 2010 and 2009, respectively.

The Company recognized a net benefit of $0.0 million, $4.0 million and $1.6 million due to the closure of certain federal and state tax years, offset by additional uncertain income tax position accruals net of interest expense of $0.1 million, $0.8 million and $1.9 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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

	Year Ended December 31,		
	2010	2009	2008
Unrecognized income tax benefits at January 1	$ 6.1	$ 12.0	$ 12.0
(Decreases) increases for positions taken in current year	—	(0.1)	1.2
(Decreases) increases for positions taken in a prior year	(0.8)	(1.3)	0.3
Decreases for settlements with taxing authorities	—	(3.6)	—
Decreases for lapses in the applicable statute of limitations	(0.1)	(0.9)	(1.5)
Unrecognized income tax benefits at December 31	$ 5.2	$ 6.1	$ 12.0

As of December 31, 2010, 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	2007 - 2009
California	2006 - 2009
Colorado	2006 - 2009
Texas	2006 - 2009
Utah	2007 - 2009

5. Earnings Per Share

Basic earnings per common share is calculated by dividing earnings available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing earnings available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share accordingly.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

5. Earnings Per Share (Continued)

The two-class method of computing earnings per share is required for those entities that have participating securities. The two class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Unvested restricted stock issued prior to January 1, 2010, under the Company's equity incentive plans, has the right to receive non-forfeitable dividends, participating on an equal basis with common stock. Unvested restricted stock issued subsequent to January 1, 2010, under the Company's stock incentive plans, no longer has the right to receive non-forfeitable dividends.

The following table shows the computation of basic and diluted net earnings per share from continuing and discontinued operations for the years ended December 31:

		Restated(1)	
	2010	2009	2008
	(In thousands, except per share amounts)		
Net earnings from continuing operations	$ 82,524	$ 47,224	$ 120,577
Less: earnings allocable to participating securities	1,199	1,134	1,735
Earnings from continuing operations available for common shareholders	$ 81,325	$ 46,090	$ 118,842
Net earnings from discontinued operations	—	6,806	12,952
Less: earnings allocable to participating securities	—	174	191
Net earnings from discontinued operations available for common shareholders	$ 81,325	$ 6,632	$ 12,761
Net earnings per share from continuing operations, basic	$ 1.54	$ 1.03	$ 2.67
Net earnings per share from discontinued operations, basic	—	0.15	0.29
Net earnings per share, basic	$ 1.54	$ 1.18	$ 2.96
Net earnings per share from continuing operations, dilutive	$ 1.52	$ 1.02	$ 2.64
Net earnings per share from discontinued operations, dilutive	—	0.15	0.28
Net earnings per share, dilutive	$ 1.52	$ 1.17	$ 2.92
Weighted average shares outstanding, basic	52,969	44,625	44,485
Add: dilutive effects of stock options	460	221	578
Weighted average shares outstanding, dilutive	53,429	44,846	45,063

(1) See Note 16 to the Financial Statements.

Options of 0.7 million, 1.6 million and 0.2 million shares were not included in the diluted earnings per share calculation for the years ended December 31, 2010, 2009 and 2008, respectively, because their effect would have been anti-dilutive.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

6. Shareholders' Equity

Shares of Class A Common Stock and Class B Stock, referred to collectively as the "Capital Stock," are 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.

Common Stock Offering

In January 2010, the Company issued 8.0 million shares of Class A Common Stock at a price of $29.25 per share. Net proceeds from this offering were $224.3 million. The Company used the net proceeds from the offering to fund a March 2010 acquisition in the Permian and to repay a portion of the outstanding borrowings under the Credit Agreement. See Note 2 to the Financial Statements.

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 (i) Credit Agreement to the greater of $35 million or 75% of net income for the four quarter period, and (ii) bond indentures to 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.

7. Equity Incentive Compensation Plans and Other Benefit Plans

The 2010 Equity Incentive Plan (the 2010 Plan), approved by the shareholders in May 2010, provides for granting of equity compensation up to an aggregate of 1,000,000 shares of Common Stock. The purpose of the 2010 Plan is to encourage ownership in the Company by key personnel whose long-term service is considered essential to the Company's continued progress and, thereby, align participants' and shareholders' interests. Stock options, stock appreciation rights (SARs), cash awards and stock awards, including restricted shares and stock units, may be granted under the 2010 Plan. The exercise price of an option may not be less than the fair market value of one share of Common Stock on the date of grant. Options and restricted stock awards granted under the 2010 Plan have historically vested in increments of 25% on each of the first four anniversary dates of the date of grant or 100% after three years. Options and RSUs granted to non-employee directors historically vest immediately. Options granted under the plan have a term of 10 years. As of December 31, 2010, the Company had 976,686 shares available to be issued under the 2010 Plan.

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. The purpose of the 2005 Plan is to encourage ownership in the Company by key personnel whose long-term service is considered essential to the Company's continued progress and, thereby, align participants' and shareholders' interests. Stock options, stock appreciation rights (SARs), cash awards and stock awards, including restricted shares and stock units, may be granted under the 2005 Plan. The exercise price of an option shall not be less than the fair market value of one share of Common Stock on the date of grant. Options and restricted stock awards granted under the 2005 Plan have historically vested in increments of 25% on each of the first four anniversary dates of the date of grant or 100% after three years. Options and RSUs granted to non-employee directors historically vest immediately.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

7. Equity Incentive Compensation Plans and Other Benefit Plans (Continued)

Options granted under the plan have a term of 10 years. As of December 31, 2010, the Company had 173,151 shares available to be issued under the 2005 Plan.

Total compensation cost recognized in the Statements of Income for grants under the Company's equity plans was $8.3 million, $7.7 million and $8.9 million in 2010, 2009 and 2008, respectively.

Stock Options

The following table summarizes stock option activity for the years ended December 31, 2010, 2009 and 2008.

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (in Thousands)(1)	Number of Shares Exercisable
Outstanding at January 1, 2008	2,527,266	$ 24.33	$ 50,843	1,558,780
Granted	89,084	41.88		
Exercised	(149,950)	19.38	4,358	
Cancelled/expired	(44,750)	29.66		
Outstanding as of December 31, 2008	2,421,650	25.16	—	1,842,532
Granted	—	—		
Exercised	(62,050)	13.52	560	
Cancelled/expired	(83,580)	28.48		
Outstanding at December 31, 2009	2,276,020	25.36	15,296	2,008,325
Granted	—	—		
Exercised	(227,100)	19.40	3,570	
Cancelled/expired	(31,695)	35.51		
Outstanding at December 31, 2010	2,017,225	$ 25.87	$ 35,974	1,884,937

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock at the end of the related period exceeds the exercise price of the option.

Stock options are granted at the fair market value of one share of Class A Common Stock on the date of grant. All outstanding options had a term of 10 years at the date of grant. The fair value of each option granted in 2008 was estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair market value of options granted during 2008:

	2008
Expected volatility	36%
Weighted-average volatility	36%
Expected dividends	1%
Expected term (in years)	5
Risk-free rate	3.2%

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

7. Equity Incentive Compensation Plans and Other Benefit Plans (Continued)

The following table summarizes information about stock options outstanding at December 31, 2010:

	Stock Options Outstanding				Stock Options Exercisable			
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighed Average Exercise Price	Aggregate Intrinsic Value (in thousands)	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighed Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$7.00-$15.00	542,100	2.75	$ 10.99	17,734	542,100	2.75	$ 10.99	$ 17,734
$15.01-$25.00	390,750	3.90	21.60	8,634	390,750	3.90	21.60	8,634
$25.01-$35.00	779,701	5.49	31.76	9,306	778,950	5.49	31.77	9,294
$35.01-$45.00	304,674	7.08	42.72	300	173,137	6.96	43.29	72
$7.00-$45.00	2,017,225	4.69	$ 25.87	35,974	1,884,937	4.50	$ 24.74	$ 35,734

As of December 31, 2010, there was $2.4 million of total unrecognized compensation cost related to stock options granted under the 2005 Plan. This cost is expected to be recognized during 2011.

Restricted Stock Units

The following is a summary of RSU activity for the year ended December 31, 2010, 2009 and 2008.

	RSUs	Weighted Average Intrinsic Value at Grant Date	Vest Date Fair Value (in Thousands)
Outstanding at January 1, 2008	506,923	$ 34.84	
Granted	572,102	11.26	
Issued	(73,414)	33.95	$ 841
Canceled/expired	(39,413)	37.58	
Outstanding at December 31, 2008(1)(2)	966,198	$ 20.83	
Granted	294,504	26.72	
Issued	(107,375)	28.98	$ 2,574
Canceled/expired	(46,034)	25.08	
Outstanding at December 31, 2009(1)(2)	1,107,293	$ 22.14	
Granted	34,529	30.94	
Issued	(246,633)	28.98	$ 7,813
Canceled/expired	(37,829)	22.20	
Outstanding at December 31, 2010(1)(2)	857,360	$ 19.67	

(1) The balance outstanding includes RSUs granted to the non-employee Directors that are 100% vested at date of grant but are subject to a deferral election before the corresponding shares are issued. For the years ended December 31, 2010, 2009 and 2008, 10,522 RSUs have vested, but the corresponding shares have not been issued; as such, these RSUs are included in the balance outstanding.

(2) The balance outstanding includes RSUs granted to executive officers and other officers that have vested in accordance with the RSU agreement, but are subject to a deferral election before the corresponding shares are issued. For the years ended December 31, 2010, 2009 and 2008, 289,335, 124,799 and 15,121 RSUs have vested, but the corresponding shares have not been issued; as such, these RSUs are included in the balance outstanding.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

7. Equity Incentive Compensation Plans and Other Benefit Plans (Continued)

The grant date fair value of RSUs issued under the 2005 Plan was determined by reference to the average high and low stock price of a share of Common Stock on the date of grant. The grant date fair value of RSUs issued under the 2010 Plan was determined by reference to the closing price of a share of Class A Common Stock on the date of grant. The Company uses historical data and projections to estimate expected restricted stock forfeitures. The expected forfeitures are then included as part of the grant date estimate of compensation cost.

As of December 31, 2010, there was $9.2 million of total unrecognized compensation cost related to unvested restricted stock granted under the equity incentive plans. That cost is expected to be recognized over a weighted average period of three years.

Performance Share Program

In March 2010, 103,794 RSUs, subject to internal performance metrics and market based vesting criteria in addition to a three-year service condition, were granted to executive officers and other officers under the 2005 Plan. The ultimate vesting of awards is contingent upon meeting the established criteria. From January 1, 2010 to December 31, 2012 the Company must maintain an interest coverage ratio of at least 2.5 to 1.0. The number of RSUs that ultimately vest is based on two equally weighted performance factors: (i) total shareholder return as compared to the Company's defined peer group for years 2010 -2012 and (ii) compounded annual production growth as measured by average annual barrels of oil equivalent per day (BOE/D).

For awards subject to performance conditions, the grant date fair value was determined by reference to the average high and low stock price of a share of Common Stock on the date of grant. The Company recognizes compensation expense for awards subject to performance conditions when it becomes probable that these conditions will be achieved. However, any such compensation expense recognized is reversed if vesting does not actually occur.

For awards subject to market conditions, the grant date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing the market-based restricted shares were as follows:

	2010
Number of simulations	100,000
Expected volatility	79%
Risk-free rate	1.36%

The total grant date fair value of the market-based restricted stock as determined by the Monte Carlo valuation model was $1.0 million and is recognized ratably over the three-year vesting period. Compensation expense is not reversed if vesting does not actually occur.

Director Fees

The Company's directors may elect to receive their annual retainer and meeting fees in the form of the Company's Common Stock issued pursuant to the Company's non-employee director deferred

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

7. Equity Incentive Compensation Plans and Other Benefit Plans (Continued)

stock and compensation plan. The plan permits 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 is made in shares. The distribution from the interest account is made in cash. Shares earned and deferred in accordance with the plan as of December 31, 2010, 2009 and 2008 were 38,462, 124,686 and 24,204, 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.

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. The Company currently matches 100% of each employee's contribution up to 8% of an employee's eligible compensation. The Company's contributions to the 401(k) Plan, net of forfeitures, for the years ended December 31, 2010, 2009 and 2008 were $1.5 million, $1.4 million and $1.4 million, respectively. Employees are eligible to participate in the 401(k) Plan on their date of hire and approximately 96% of the Company's employees participated in the 401(k) Plan in 2010.

8. Derivative Instruments

The Company uses financial derivative instruments as part of its price risk management program to achieve a more predictable, economic cash flow from its oil and natural gas production by reducing its exposure to price fluctuations. The Company has entered into financial commodity swap and collar contracts to fix the floor and ceiling prices received for a portion of the Company's oil and natural gas production. The terms of the 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. The Company periodically enters into interest rate derivative agreements to protect against changes in interest rates on its floating rate debt. For further discussion related to the fair value of the Company's derivatives see Note 9 to the Financial Statements.

As of December 31, 2010, the Company had the following commodity hedges:

	2011	2012	2013
Oil Bbl/D:	18,020	14,000	8,000
Natural Gas MMBtu/D:	15,000	15,000	—

Based on NYMEX strip pricing as of December 31, 2010, the Company expects to make hedge payments under existing derivative contracts of $68.8 million during the next twelve months.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

8. Derivative Instruments (Continued)

Discontinuance of Hedge Accounting

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 elected to de-designate all of its commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009. As a result, subsequent to December 31, 2009, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCL.

At December 31, 2009, AOCL included $97.4 million ($60.4 million, net of income tax) of unrealized losses, representing the change in the fair value of the Company's open commodity and interest rate derivative contracts designated as cash flow hedges as of that balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such fair values at December 31, 2009 are frozen in AOCL as of the de-designation date and reclassified into earnings as the original hedge transactions settle. During the year ended December 31, 2010, $26.7 million ($16.6 million net of income tax) of derivative losses relating to de-designated commodity and interest rate hedges were reclassified from AOCL into earnings.

At December 31, 2010, AOCL included $70.7 million ($43.8 million, net of income tax) of unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. In the next 12 months, the Company expects to reclassify into earnings from AOCL $61.8 million ($38.3 million net of income tax) related to the de-designated derivative contracts.

In the fourth quarter of 2010, the Company terminated interest rate derivatives instruments, which were previously designated as cash flow hedges. The termination resulted in a cash settlement of $10.8 million, offset by a fair value gain of $8.9 million. The net loss of $1.9 million is included in Realized and unrealized (loss) gain on derivative, net.

The following tables detail the fair value of derivatives recorded on the Company's Balance Sheets, by category:

	As of December 31, 2010			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Total derivatives designated as hedging instruments		$ —		$ —
Current:				
Commodity	Derivative assets	$ 2.7	Derivative liabilities	$ 84.9
Long term:				
Commodity	Derivative assets	2.1	Derivative liabilities	33.5
Total derivatives		$ 4.8		$ 118.4

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

8. Derivative Instruments (Continued)

	As of December 31, 2009			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	$ 15.4	N/A	$ —
Commodity	N/A	—	Derivative liabilities	30.6
Interest Rate	N/A	—	Derivative assets(1)	3.5
Interest Rate	N/A	—	Derivative liabilities	2.7
Long term:				
Commodity	Derivative assets	0.4	N/A	—
Commodity	N/A	—	Derivative liabilities	72.8
Interest rate	Derivative assets	0.3	N/A	—
Interest rate	N/A	—	Derivative liabilities	3.0
Total derivatives designated as hedging instruments		$ 16.1		$ 112.6
Current:				
Commodity		$ —	Derivative assets(1)	$ 0.4
Commodity		—	Derivative liabilities	0.5
Total derivatives not designated as hedging instruments		$ —		$ 0.9
Total derivatives		$ 16.1		$ 113.5

(1) Amounts are netted against derivative asset balances with the same counterparty, and, therefore, are presented as a net asset on the Company's Balance Sheets.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

8. Derivative Instruments (Continued)

The tables below summarize the location and the amount of derivative instrument gains (losses) before income taxes reported in the Statements of Income for the periods indicated:

(in millions) Derivatives cash flow hedging relationships	Location of Gain (Loss) Recognized in Income	Year Ended December 31 2010	Restated(1) 2009
Commodity			
Gain (loss) recognized in AOCL (effective portion)	Accumulated other comprehensive (loss)	$ —	$ (206.4)
(Loss) gain reclassified from AOCL into income (effective portion)	Sales of oil and gas	(18.4)	58.8
Gain reclassified from AOCL into income (effective portion)	Earnings from discontinued operations	—	20.5
(Loss) recognized in income (ineffective Portion)	Realized and unrealized (loss) gain on derivatives, net	—	(0.6)
Interest rate			
(Loss) gain recognized in AOCL (effective portion)	Accumulated other comprehensive (loss)	$ —	$ (2.7)
(Loss) gain reclassified from AOCL into income (effective portion)	Interest expense	(8.3)	(7.0)

Amount of gain or (loss) recognized in income on derivatives not designated as hedging instruments under authoritative guidance for the periods indicated (in millions):

Derivatives not designated as Hedging Instruments under authoritative guidance	Location of Gain (Loss) Recognized in Income	Year Ended December 31, 2010	2009
Commodity	Realized and unrealized (loss) gain on derivatives, net	$ (23.2)	$ (7.2)
Commodity	Earnings from discontinued operations	—	(0.5)
Interest Rates	Realized and unrealized (loss) gain on derivatives, net	(8.6)	—

(1) See Note 16 to the Financial Statements.

Credit Risk

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the agreements with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions, the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that the Company would have incurred if all counterparties to its

8. Derivative Instruments (Continued)

derivative contracts failed to perform at December 31, 2010 was $4.8 million. As of December 31, 2010, the Company's largest four counterparties accounted for 82% of the value of its total derivative positions.

As of December 31, 2010, the counterparties to the Company's commodity derivative contracts consist of eight financial institutions. The Company's counterparties or their affiliates are generally lenders under the Company's senior revolving credit facility, as amended. As a result, the counterparties to the Company's derivative agreements share in the collateral supporting the Company's Credit Agreement. The Company is not generally required to post additional collateral under derivative agreements.

Certain of the Company's derivative agreements contain provisions that require cross defaults and acceleration of those instruments to any material debt. If the Company was to default on any of its material debt agreements, it would be a violation of these provisions, and the counterparties to the derivative instruments could request immediate payment on derivative instruments that are in a net liability position at that time. As of December 31, 2010, the Company owed a net derivative liability to seven of its counterparties, the fair value of which was $118.4 million.

9. Fair Value Measurement

The authoritative guidance for fair value measurements 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. The Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) for valuation as a practical expedient for assigning fair value. Oil swaps, natural gas swaps and interest rate swaps are valued using models which are based on active market data and are classified within Level 2 of the fair value 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. Fair value of all derivative instruments are estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The fair value of all derivative instruments are estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services, and the Company has made no adjustments to the obtained prices. The pricing services publish observable market information from multiple brokers and exchanges. All valuations were compared against counterparty valuations to verify the reasonableness of prices. 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

9. Fair Value Measurement (Continued)

oil collars, natural gas collars and natural gas basis swaps. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

The following tables set forth by level within the fair value hierarchy the Company's net derivative assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2010 and December 31, 2009.

Liabilities Measured at Fair Value on a Recurring Basis

December 31, 2010 (in millions)	Total	Level 1	Level 2	Level 3
Commodity derivative liability	$ (113.6)	$ —	$ (11.8)	$ (101.8)
Interest rate swaps liability	—	—	—	—
Total liabilities at fair value	$ (113.6)	$ —	$ (11.8)	$ (101.8)

December 31, 2009 (in millions)	Total	Level 1	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)

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 the Company 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)	Year ended December 31, 2010	Year ended December 31, 2009	Year ended December 31, 2008
Fair value asset (liability), beginning of period	$ (26.0)	$ 172.5	$ (194.3)
Total realized and unrealized gains (losses)			
Realized and unrealized (loss) gain included in income	(37.4)	71.0	—
Unrealized (loss) gain included in accumulated other comprehensive loss	—	(201.9)	196.0
Purchases, sales and settlements, net	(38.4)	(71.0)	170.8
Transfers in and/or out of Level 3	—	3.4	—
Fair value asset (liability), end of period	$ (101.8)	$ (26.0)	$ 172.5
Total unrealized (losses) gain included in income related to financial assets and liabilities still on the Balance Sheet at December 31, 2010 and 2009	$ (75.8)	$ 0.4	$ —

9. Fair Value Measurement (Continued)

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 8 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, the 10.25% senior notes due 2014, and the 6.75% senior notes due 2020 were estimated based on quoted market prices. The fair values of the Company's derivative instruments and other investments are discussed above.

	December 31,2010		December 31, 2009	
(in millions)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Line of credit	$ 5	$ 5	$ —	$ —
Senior secured revolving credit facility	170	170	372	372
8.25% Senior subordinated notes due 2016	200	210	200	196
10.25% Senior notes due 2014	439	518	437	487
6.75% Senior notes due 2020	300	303	—	—
	$ 1,114	$ 1,206	$ 1,009	$ 1,055

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The Company also applies fair value accounting guidance to measure non-financial assets and liabilities such as business acquisitions, proved oil and gas properties, and asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. These items are primarily valued using the present value of estimated future cash inflows and/or outflows. Given the unobservable nature of these inputs, they are deemed to be Level 3. In accounting for its 2010 business acquisitions, the Company determined the fair value of assets and liabilities acquired. See Note 2 to the Financial Statements for additional discussion. 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.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

10. Commitments and Contingencies

Operating Leases and Other Commitments

The Company leases corporate and field offices in California, Colorado and Texas. 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. The Company also uses operating leases to finance vehicles. Rent expense with respect to these lease commitments for the years ended December 31, 2010, 2009 and 2008 was $2.6 million, $2.6 million and $2.1 million, respectively. The Company currently has two drilling rigs under contract. Both expire in 2011. All other rigs currently operate on a well-by-well basis and, therefore, can be released without penalty at the conclusion of drilling on current in-progress wells. Additionally, the Company enters into certain firm commitments to transport natural gas production to market and to transport natural gas to its cogeneration and conventional steam generation facilities. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity is used or not. The table below shows the Company's future minimum payments under non-cancelable operating leases and other commitments as of December 31, 2010.

(in millions)	Total	2011	2012	2013	2014	2015	Thereafter
Operating leases(1)	$ 14.4	$ 2.7	$ 2.7	$ 2.7	$ 2.6	$ 2.3	$ 1.4
Drilling rig commitments(2)	2.0	2.0	—	—	—	—	—
Firm natural gas transportation contracts(3)	278.1	24.9	29.3	30.1	32.1	32.1	129.6
Total	$ 294.5	$ 29.6	$ 32.0	$ 32.8	$ 34.7	$ 34.4	$ 131.0

(1) Includes operating leases related to office facilities, equipment, vehicles and aircraft.

(2) Excludes obligations related to rigs drilling on a well-by-well basis.

(3) The Company enters into certain firm commitments to transport natural gas production to market and to transport natural gas for use in its cogeneration and conventional steam generation facilities. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity is used or not. The commitment above includes the firm transportation agreements with El Paso Corporation for an average total of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. The commitment is based on the expectation that the project will proceed and be in service in mid-2011.

E. Texas Gathering System

In July 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. The transaction was treated as a financing obligation. Accordingly, the $16.7 million net book value of the property is being 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 payments under the agreements are recorded as gathering expense and a portion as interest expense, with the balance being recorded as a reduction to the financing obligation. There are no minimum payments required under these agreements. For the years ended December 31, 2010 and 2009, the Company incurred $6.7 million and $2.0 million, respectively, under the agreements.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

10. Commitments and Contingencies (Continued)

Carry and Earning Agreement

On January 14, 2011, the Company entered into an amendment relating to certain contractual obligations to a third party co-owner of certain Piceance assets in Colorado. The amendment waives the $0.2 million penalty for each well not spud by February 2011. The Company is obligated to pay the first $4.5 million of costs incurred by such third party in connection with the construction, on behalf of both the Company and such third party, of either an extension of an existing access road or a new access road. If by December 31, 2012 (which date may, under certain circumstances, be extended until December 31, 2014), the Company has not expended $9 million ($4.5 million of which would otherwise be such third party's responsibility) in road construction costs, then it will be obligated to pay the third party 50% of the difference between $12 million and the actual amount expended on road construction as of such date. In addition, the amendment extends the date by which the Company must complete its drilling obligations on the North Parachute property to January 31, 2020.

Uinta Crude Oil Sales Contract

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 3,300 Bbl/D in 2010. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of our crude oil sales customer in Utah could impact the marketability of a portion of our Utah crude oil volumes. Please see Item 1A. Risk Factors—"We may not be able to deliver minimum crude oil volumes required by our sales contract."

Environmental Matters

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.

Legal Matters

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 the Company may be required to pay are up to approximately $7 million.

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, results of operations or operating cash flows.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

11. Subsequent Event

In July 2009, the Company received notice of a proposed $69.6 million civil penalty from the Bureau of Land Management (BLM) relating to the Company's alleged noncompliance during 2007 with regulations relating to the operation and positioning of certain valves in its Uinta operations. In 2007, upon learning of the alleged noncompliance, the Company immediately remediated the noncompliance and cooperated fully with the BLM's investigation. The Company believes no production was lost or stolen, all royalties were paid and there was no harm to the environment, all of which have been acknowledged by the BLM. In February 2011, the Company negotiated a settlement with the BLM in the amount of $2.1 million, the amount previously reserved by the Company in respect of the penalty.

12. Oil and Gas Properties, Buildings and Equipment

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

	2010	2009
Oil and gas:		
Proved properties(1)	$ 3,182,305	$ 2,423,956
Unproved properties(2)	217,253	249,648
	3,399,558	2,673,604
Less accumulated depreciation, depletion and amortization	(757,264)	(583,077)
	2,642,294	2,090,527
Commercial and other:		
Land	—	66
Machinery, drilling rigs, and equipment	24,988	25,631
Buildings and improvements	7,434	5,911
Vehicles	6,849	6,310
	39,271	37,918
Less accumulated depreciation	(25,773)	(22,060)
	13,498	15,858
	$ 2,655,792	$ 2,106,385

(1) Includes cogeneration facilities.

(2) Unproved properties includes acquisition costs for properties to which proved developed producing and proved undeveloped reserves are also attributed. At December 31, 2010 and 2009 unproved properties included $5 million of acquisition costs for unevaluated properties. The Company assesses these properties annually and determined that no impairment was necessary during 2010 or 2009.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

12. Oil and Gas Properties, Buildings and Equipment (Continued)

Capitalized Interest

Interest capitalization begins at the acquisition date and continues as long as development activities to prepare the asset for intended use are ongoing. During 2010 the Company capitalized interest on its Piceance and Permian assets as development activities were ongoing. During 2009 and 2008, the Company capitalized interest on its Piceance and E. Texas assets as development activities were ongoing. In the future, interest capitalization on acquisition costs will depend on whether or not development activities are ongoing. Development activities consist primarily of drilling wells and installing the necessary equipment for production to commence. Interest capitalization ceases when the wells have been completed. Interest cost is capitalized as a component of property cost for development projects that require greater than six months to be readied for their intended use. The Company does not generally engage in longer lead time development projects as its primarily development costs to the drilling of wells for which the drilling period is generally less than 30 days. Capitalized interest is added to the depreciable base of the assets and is expensed on a units-of-production basis over the life of the respective project.

Dry Hole, Abandonment, and Impairment

The Company recorded dry hole, abandonment and impairment charges of $1.5 million, $5.2 million and $9.9 million in 2010, 2009 and 2008, respectively. In 2010, the Company recorded dry hole, abandonment, and impairment expense primarily due to a mechanical failure encountered on one well in the Piceance. The well was abandoned in favor of drilling a replacement well from the same well pad. In 2009, the Company recorded dry hole, abandonment and impairment expense primarily due to a $4.2 million impairment charge related to the write-down of a rig to its fair market value. See Note 9 to the Financial Statements. In 2008, the Company recorded dry hole, abandonment and impairment expense primarily due to $7.3 million for technical difficulties that were encountered on five wells in the Piceance before reaching total depth. These holes were abandoned in favor of drilling to the same bottom-hole location by drilling new wells. Additionally, the Company recorded an impairment charge of $2.4 million related to the write-down of a rig to its fair market value.

13. Asset Retirement Obligations (AROs)

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

(in thousands)	2010	2009
Beginning balance at January 1	$ 43,487	$ 41,967
Liabilities incurred	3,721	1,407
Liabilities settled	(1,832)	(1,030)
Disposition of assets	—	(2,752)
Liabilities assumed	3,498	—
Accretion expense	4,569	3,895
Ending balance at December 31	$ 53,443	$ 43,487

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

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

13. Asset Retirement Obligations (AROs) (Continued)

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.

14. Supplemental Information about Oil & Gas Producing Activities (Unaudited)

The reserve estimates as of December 31, 2010 and 2009 presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance issued by the Financial Accounting Standards Board effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's "*Modernization of Oil and Gas Reporting*" rule, which was also effective for annual reports for fiscal years ending on or after December 31, 2009.

The above-mentioned rules include updated definitions of proved oil and gas reserves, proved undeveloped oil and gas reserves, oil and gas producing activities, and other terms used in estimating proved oil and gas reserves. Proved oil and gas reserves as of December 31, 2010 and 2009 were calculated based on the prices for oil and gas during the twelve month period before the reporting date, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, rather than the year-end spot prices, which had been used in years prior to 2009. This average price is also used in calculating the aggregate amount and changes in future cash inflows related to the standardized measure of discounted future cash flows. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Data prior to December 31, 2009 presented throughout this footnote is not required to be, nor has it been, updated based on the new guidance.

For all years presented, the estimates of proved reserves and related valuations were based 100% on reports prepared by the Company's independent petroleum engineers, DeGolyer and MacNaughton ("D&M"). D&M is an independent petroleum engineering consulting firm has provided consulting services throughout the world for over 70 years. Proved reserve estimates included herein conform to the definitions prescribed by the SEC. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

14. Supplemental Information about Oil & Gas Producing Activities (Unaudited) (Continued)

Changes in Estimated Reserve Quantities

As of December 31, 2010, all of the Company's oil and natural gas reserves are attributable to properties within the United States. A summary of the Company's changes in quantities of proved oil and natural gas reserves for the years ended December 31, 2010, 2009 and 2008, are as follows:

	2010			2009			2008		
	Oil MBbl	Gas MMcf	MBOE	Oil MBbl	Gas MMcf	MBOE	Oil MBbl	Gas MMcf	MBOE
Proved developed and undeveloped reserves:									
Beginning of year	129,940	632,178	235,303	125,251	724,135	245,940	116,602	315,464	169,179
Revision of previous estimates	4,288	(46,860)	(3,522)	2,786	(34,564)	(2,975)	(10,211)	(41,570)	(17,139)
Improved recovery	1,700	—	1,700	—	—	—	7,600	—	7,600
Extensions and discoveries	12,774	43,469	20,019	8,989	54,664	18,100	18,700	145,800	43,000
Property sales	—	—	—	—	(126,600)	(21,100)	—	—	—
Production	(7,925)	(23,989)	(11,923)	(7,186)	(22,657)	(10,962)	(7,440)	(25,559)	(11,700)
Purchase of reserves in place	25,404	25,394	29,636	100	37,200	6,300	—	330,000	55,000
End of year	166,181	630,192	271,213	129,940	632,178	235,303	125,251	724,135	245,940
Proved developed reserves:									
Beginning of year	82,870	255,520	125,456	74,616	361,575	134,879	78,339	147,346	102,897
End of year	88,917	268,566	133,678	82,870	255,520	125,456	74,616	361,575	134,879

Notable changes in proved reserves for the year ended December 31, 2010 included:

- ***Purchase of reserves in place.*** The acquisition reserves include 29 MMBOE purchased in the Permian.
- ***Extensions and discoveries.*** In 2010, total extensions and discoveries of 20 MMBOE resulted from the Company's drilling and completion activities primarily in the Diatomite, the Permian, Brundage Canyon, and Darco assets.
- ***Revisions to previous estimates.*** In 2010, negative revisions to previous estimates decreased proved reserves by a net amount of 4 MMBOE due to performance and as a result of the Company's future development plans. Specifically, the decrease is due to a 4 MMBOE decrease in East Texas, a 4 MMBOE decrease in the Piceance, and a 1 MMBOE decrease in Uinta, offset by a 1 MMBOE increase in the Permian and a 4 MMBOE increase in California.

Notable changes in proved reserves for the year ended December 31, 2009 included:

- ***Purchase of reserves in place.*** The acquisition reserves include 6 MMBOE purchased in the Piceance.
- ***Extensions and discoveries.*** In 2009, total extensions and discoveries of 18 MMBOE resulted from the Company's drilling and completion activities primarily at the Diatomite field in California and the Piceance field in Colorado.
- ***Revisions to previous estimates.*** In 2009, negative revisions to previous estimates decreased proved reserves by a net amount of 3 MMBOE due to performance. Specifically, the decrease is

14. Supplemental Information about Oil & Gas Producing Activities (Unaudited) (Continued)

attributable to a 1 MMBOE increase in California, a 5 MMBOE increase in the Piceance and Uinta, offset by a 9 MMBOE decrease in E. Texas.

- ***Property sales.*** The reserves sales of 21 MMBOE resulted from the sale of the Company's DJ assets in 2009.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure has been prepared using the average price during the 12-month period, determined as an un-weighted 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 income tax rates (adjusted for income 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.

Changes in the demand for oil and natural gas, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. This table should not be construed to be an estimate of the current market value of the Company's proved reserves. Management does not rely upon the information that follows in making investment decisions.

	Year ended December 31,		
	2010	2009	2008
		(in thousands)	
Future cash inflows	$ 14,354,627	$ 9,028,991	$ 7,384,692
Future production costs	(4,446,183)	(3,826,832)	(2,920,664)
Future development costs	(1,789,001)	(1,159,465)	(1,196,394)
Future income tax expense	(2,272,184)	(969,771)	(511,291)
Future net cash flows	5,847,259	3,072,923	2,756,343
10% annual discount for estimated timing of cash flows	(3,048,103)	(1,627,176)	(1,620,762)
Standardized measure of discounted future net cash flows	$ 2,799,156	$ 1,445,747	$ 1,135,581
Average sales prices at December 31:(1)			
Oil ($/Bbl)	$ 69.04	$ 52.06	$ 30.03
Gas ($/Mcf)	4.57	3.58	4.85
BOE	52.93	38.37	30.92

(1) The new SEC and FASB reserves reporting rules require the use of 12-month average commodity prices effective for 2010 and 2009, instead of year-end commodity prices used in 2008.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

14. Supplemental Information about Oil & Gas Producing Activities (Unaudited) (Continued)

Changes in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Year ended December 31,		
	2010	2009 (in thousands)	2008
Standardized measure—beginning of year	$ 1,445,747	$ 1,135,581	$ 2,419,506
Sales of oil and gas produced, net of production costs	(406,390)	(353,052)	(497,866)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	1,724,212	637,882	(2,686,941)
Revisions of previous quantity estimates	(49,784)	(33,943)	(144,466)
Improved recovery	24,033	—	64,058
Extensions and discoveries	283,011	206,542	362,435
Change in estimated future development costs	(152,096)	(52,824)	(352,061)
Purchases of reserves in place	307,205	29,348	667,862
Sales of reserves in place	—	(138,265)	—
Previously estimated development costs incurred during the period	144,086	110,200	173,184
Accretion of discount	184,917	131,745	354,672
Income taxes	(593,272)	(190,727)	631,372
Other	(112,513)	(36,740)	143,826
Net increase (decrease)	1,353,409	310,166	(1,283,925)
Standardized measure—end of year	$ 2,799,156	$ 1,445,747	$ 1,135,581

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities

The following costs were incurred in oil and natural gas property acquisition, exploration, and development activities during the years ended December 31:

	2010	2009 (in thousands)	2008
Property acquisitions			
Proved properties	$ 334,409	$ 13,497	$ 667,996
Unproved properties	—	—	—
Development(1)	320,927	138,168	385,599
Exploration(2)	2,310	209	9,700
Total(3)	$ 657,646	$ 151,874	$ 1,063,295

(1) Development costs include $7.1 million, $4.9 million and $0.1 million charged to expense during 2010, 2009 and 2008, respectively.

(2) Exploration costs include $2.3 million, $0.2 million and $2.4 million that were charged to expense during 2010, 2009 and 2008, respectively.

(3) The total above does not reflect $28.3 million, $30.1 million, and $23.2 million of capitalized interest incurred in 2010, 2009, and 2008, respectively.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

15. Selected Quarterly Financial Data (Unaudited)

	Operating Revenues	Earnings (Loss) From Continuing Operations	Earnings (Loss) From Discontinued Operations	Net Earnings (Loss)	Basic Net Earnings (Loss) From Continuing Operations Per Share(1)	Basic Net (Loss) Earnings From Discontinued Operations Per Share(2)	Diluted Net Earnings (Loss) From Continuing Operations Per Share(2)	Diluted Net (Loss) Earnings From Discontinued Operations Per Share(2)
2010								
First Quarter	$ 166,012	$ 17,669	$ —	$ 17,669	$ 0.34	$ —	$ 0.34	$ —
Second Quarter	164,457	89,023	—	89,023	1.65	—	1.64	—
Third Quarter	166,040	(3,023)	—	(3,023)	(0.06)	—	(0.06)	—
Fourth Quarter	180,001	(21,145)	—	(21,145)	(0.40)	—	(0.40)	—
	$ 676,510	$ 82,524	$	$ 82,524	$ 1.54	$	$ 1.52	$
2009 (Restated) (1)								
First Quarter	$ 139,561	$ 28,590	$ 6,408	$ 34,998	$ 0.63	$ 0.14	$ 0.63	$ 0.14
Second Quarter	130,265	(12,888)	(92)	(12,980)	(0.28)	—	(0.28)	—
Third Quarter	141,809	18,520	487	19,007	0.41	0.01	0.40	0.01
Fourth Quarter	147,768	13,002	3	13,005	0.29	—	0.29	—
	$ 559,403	$ 47,224	$ 6,806	$ 54,030	$ 1.03	$ 0.15	$ 1.02	$ 0.15

(1) See Note 16 to the Financial Statements.

(2) The sum of the individual quarterly net earnings (loss) per common share amounts may not agree with year-to-date net earnings (loss) per common share as each quarterly computation is based on the weighted-average number of common shares outstanding during that period. Potentially dilutive securities were included in the computation of diluted net earnings (loss) per common share for each quarter in which the Company reported net income.

Out of Period Adjustments

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 2009 impact of the adjustment was $1.9 million. Management concluded the impact was immaterial to 2009 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.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

15. Selected Quarterly Financial Data (Unaudited) (Continued)

The changes to the previously reported Quarterly Statements of Income are as follows:

	Three months ended March 31, 2009	
	Reported	Restated(1)
REVENUES		
Sales of oil and gas	$ 127,869	$ 121,710
Sales of electricity	10,270	10,270
Gas marketing	7,581	7,581
Realized and unrealized gain on derivatives, net	37,164	22,894
Interest and other income, net	283	283
	183,167	162,738
EXPENSES		
Operating costs—oil and gas production	37,384	37,384
Operating costs—electricity generation	8,783	8,783
Production taxes	5,652	5,652
Depreciation, depletion & amortization—oil and gas production	36,398	36,398
Depreciation, depletion & amortization—electricity generation	959	959
Gas marketing	7,284	7,284
General and administrative	13,294	13,294
Interest	10,050	10,050
Dry hole, abandonment, impairment and exploration	122	122
	119,926	119,926
Earnings from continuing operations before income taxes	63,241	42,812
Provision for income taxes	21,462	14,222
Earnings from continuing operations	41,779	28,590
Earnings (loss) from discontinued operations, net of income taxes	(6,781)	6,408
Net earnings	$ 34,998	$ 34,998
Net earnings from continuing operations per share, Basic	0.92	0.63
Net (loss) earnings from discontinued operations per share, Basic	(0.15)	0.14
Net earnings per share, Basic	$ 0.77	$ 0.77
Net earnings from continuing operations per share, Diluted	0.92	0.63
Net (loss) earnings from discontinued operations per share, Diluted	(0.15)	0.14
Net earnings per share, Diluted	$ 0.77	$ 0.77

(1) See Note 16 to the Financial Statements.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

15. Selected Quarterly Financial Data (Unaudited) (Continued)

	Three months ended June 30, 2009		Six months ended June 30, 2009	
	Reported	Restated(1)	Reported	Restated(1)
REVENUES				
Sales of oil and gas	$ 118,793	$ 118,793	$ 246,662	$ 240,503
Sales of electricity	6,624	6,624	16,895	16,895
Gas marketing	4,848	4,848	12,429	12,429
Realized and unrealized (loss) gain on derivatives, net	(31,130)	(31,130)	6,034	(8,235)
Interest and other income, net	806	806	1,088	1,088
	99,941	99,941	283,108	262,680
EXPENSES				
Operating costs—oil and gas production	34,738	34,738	72,122	72,122
Operating costs—electricity generation	6,397	6,397	15,179	15,179
Production taxes	4,885	4,885	10,537	10,537
Depreciation, depletion & amortization—oil and gas production	34,371	34,371	70,769	70,769
Depreciation, depletion & amortization—electricity generation	1,028	1,028	1,987	1,987
Gas marketing	4,232	4,232	11,516	11,516
General and administrative	13,164	13,164	26,457	26,457
Interest	10,589	10,589	20,639	20,639
Extinguishment of debt	10,492	10,492	10,494	10,494
Dry hole, abandonment, impairment and exploration	17	17	140	140
	119,913	119,913	239,840	239,840
(Loss) earnings from continuing operations before income taxes	(19,972)	(19,972)	43,268	22,840
Provision for income taxes	(7,204)	(7,084)	14,258	7,138
(Loss) earnings from continuing operations	(12,768)	(12,888)	29,010	15,702
(Loss) earnings from discontinued operations, net of income taxes	(212)	(92)	(6,991)	6,317
Net (loss) earnings	$ (12,980)	$ (12,980)	$ 22,019	$ 22,019
Net (loss) earnings from continuing operations per share, Basic	(0.28)	(0.28)	0.63	0.34
Net (loss) earnings from discontinued operations per share, Basic	—	—	(0.15)	0.14
Net (loss) earnings per share, Basic	$ (0.28)	$ (0.28)	$ 0.48	$ 0.48
Net (loss) earnings from continuing operations per share, Diluted	(0.28)	(0.28)	0.63	0.34
Net (loss) earnings from discontinued operations per share, Diluted	—	—	(0.15)	0.14
Net (loss) earnings per share, Diluted	$ (0.28)	$ (0.28)	$ 0.48	$ 0.48

(1) See Note 16 to the Financial Statements.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

15. Selected Quarterly Financial Data (Unaudited) (Continued)

	Three months ended September 30, 2009		Nine months ended September 30, 2009	
	Reported	Restated(1)	Reported	Restated(1)
REVENUES				
Sales of oil and gas	$ 127,455	$ 127,455	$ 374,117	$ 367,958
Sales of electricity	9,137	9,137	26,032	26,032
Gas marketing	5,217	5,217	17,646	17,646
Realized and unrealized gain (loss) on derivatives, net	531	531	6,565	(7,704)
Gain on sale of assets	828	828	828	828
Interest and other income, net	287	287	1,375	1,375
	143,455	143,455	426,563	406,135
EXPENSES				
Operating costs—oil and gas production	39,195	39,195	111,317	111,317
Operating costs—electricity generation	6,892	6,892	22,071	22,071
Production taxes	3,874	3,874	14,411	14,411
Depreciation, depletion & amortization—oil and gas production	33,502	33,502	104,271	104,271
Depreciation, depletion & amortization—electricity generation	951	951	2,938	2,938
Gas marketing	4,633	4,633	16,149	16,149
General and administrative	10,686	10,686	37,143	37,143
Interest	14,562	14,562	35,201	35,201
Extinguishment of debt	329	329	10,823	10,823
Dry hole, abandonment, impairment and exploration	69	69	209	209
	114,693	114,693	354,533	354,533
Earnings from continuing operations before income taxes	28,762	28,762	72,030	51,602
Provision for income taxes	10,423	10,242	24,681	17,380
Earnings from continuing operations	18,339	18,520	47,349	34,222
Earnings (loss) from discontinued operations, net of income taxes	668	487	(6,323)	6,804
Net earnings	$ 19,007	$ 19,007	$ 41,026	$ 41,026
Net earnings from continuing operations per share, Basic	0.41	0.41	1.04	0.75
Net earnings (loss) from discontinued operations per share, Basic	0.01	0.01	(0.14)	0.15
Net earnings per share, Basic	$ 0.42	$ 0.42	$ 0.90	$ 0.90
Net earnings from continuing operations per share, Diluted	0.40	0.40	1.03	0.74
Net earnings (loss) from discontinued operations per share, Diluted	0.01	0.01	(0.14)	0.15
Net earnings per share, Diluted	$ 0.41	$ 0.41	$ 0.89	$ 0.89

(1) See Note 16 to the Financial Statements.

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

16. Restatement of Previously Issued Financial Statements

At the time of the DJ asset sale, the Company had designated derivative instruments as cash flow hedges from the forecasted sale of natural gas produced by the DJ assets. The Company determined that as a result of the sale of the DJ assets, the forecasted transactions were no longer probable of occurring. Accordingly, the Company discontinued hedge accounting for those hedges and the accumulated amount within accumulated other comprehensive loss related to those derivatives was included in earnings from continuing operations. In addition, all recurring income statement impacts from the derivatives designated as hedges of future production expected from the DJ assets were classified as continuing operations. The Company had previously classified the realized gains on derivative instruments designated as cash flow hedges from the forecasted sales of natural gas produced by the DJ assets as part of continuing operations on the basis that its hedging program was managed for the purposes of corporate risk management and that hedge gains and losses were not indicative of individual asset performance when determining the amounts to include in discontinued operations.

However, after discussions with the staff of the SEC, the Company determined that such gains should have been classified as part of discontinued operations, on the basis that these hedges were documented as relating to the DJ assets to achieve cash flow hedge accounting in accordance with authoritative literature.

The effect of correcting the classification of these gains resulted in a decrease in earnings from continuing operations of $12.7 million ($0.28 per diluted share) and $1.2 million ($0.02 per diluted share) for 2009 and 2008, respectively, with a corresponding increase in earnings and earnings per diluted share from discontinued operations, net of income taxes for the same periods. The change in classification did not affect net earnings for any of the Company's previously issued financial statements, nor did it have an impact on 2009, 2008 or any of the Company's previously issued Balance Sheets, Statements of Shareholders' Equity or Statements of Cash Flows. The following table reports the full effect of the change in classification of the Statements of Income for 2009 and 2008:

BERRY PETROLEUM COMPANY

Notes to the Financial Statements (Continued)

16. Restatement of Previously Issued Financial Statements (Continued)

The changes to the previously reported Statements of Income are as follows:

	For the Years Ended December 31,			
	Reported 2009	Restated 2009	Reported 2008	Restated 2008
REVENUES				
Sales of oil and gas	$ 506,691	$ 500,532	$ 649,248	$ 647,357
Realized and unrealized gain (loss) on derivatives, net	6,514	(7,756)	(213)	(358)
Earnings from continuing operations before income taxes	88,317	67,888	192,084	190,193
Provision for income taxes	28,349	20,664	70,308	69,616
Earnings from continuing operations	59,968	47,224	121,776	120,577
(Loss) earnings from discontinued operations, net of income taxes	(5,938)	6,806	11,753	12,952
Net earnings	$ 54,030	$ 54,030	$ 133,529	$ 133,529
Net earnings from continuing operations per share, Basic	1.31	1.03	2.70	2.67
Net (loss) earnings from discontinued operations per share, Basic	(0.13)	0.15	0.26	0.29
Net earnings per share, Basic	$ 1.18	$ 1.18	$ 2.96	$ 2.96
Net earnings from continuing operations per share, Diluted	1.30	1.02	2.66	2.64
Net (loss) earnings from discontinued operations per share, Diluted	(0.13)	0.15	0.26	0.28
Net earnings per share, Diluted	$ 1.17	$ 1.17	$ 2.92	$ 2.92

The changes to the previously reported Discontinued Operations are as follows:

	For the Years Ended December 31,			
	Reported 2009	Restated 2009	Reported 2008	Restated 2008
Sales of oil and gas	$ 5,396	$ 11,555	$ 48,729	$ 50,620
Realized and unrealized gain on derivatives, net	—	13,786	—	—
Loss on sale of asset	(908)	(908)	—	—
Other revenue	623	623	2,072	2,072
Total revenues	5,111	25,056	50,801	52,692
Total expenses	16,283	15,799	32,263	32,263
(Loss) income from discontinued operations, before income taxes	(11,172)	9,257	18,538	20,429
Income tax (benefit) expense	(5,234)	2,451	6,785	7,477
(Loss) earnings from discontinued operations, net of income taxes	$ (5,938)	$ 6,806	$ 11,753	12,952

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of December 31, 2010, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended (the Exchange Act).

Our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2010, our disclosure controls and procedures are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Internal control over financial reporting is defined in Rule 13a-15(f) and 15d-15(f) promulgated under the Securities Exchange Act of 1934, as amended, as a process designed by, or under the supervision of, our principal executive and principal financial officers, or persons performing similar functions, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;

- 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 our management and Directors; and

- provide reasonable assurance regarding prevention or the timely detection of unauthorized acquisition, or the use or disposition of our 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. Additionally, 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.

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control—Integrated Framework,* management concluded that our internal control over financial reporting was effective as of December 31, 2010. The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Management's Consideration of the Restatement

In connection with the restatement of our 2009 and 2008 financial statements set forth in this Annual Report on Form 10-K, management evaluated whether (i) the presentation of realized gains (losses) on derivatives instruments designated as cash flow hedges from the forecasted sale of natural gas produced by the DJ assets and (ii) amounts reclassified from Accumulated other comprehensive loss into earnings when the hedging relationship was discontinued as part of continuing operations versus discontinued operations was indicative of a deficiency in internal control over financial reporting. Management concluded that a deficiency in internal control over financial reporting did not exist. In reaching this conclusion, management considered the results of its overall assessment of our financial reporting process and controls as well as the specific procedures and controls undertaken by management to evaluate the application of generally accepted accounting principles in determining the appropriate presentation for the aforementioned transactions. Management performed a thorough, well-reasoned evaluation when determining (i) the appropriate presentation of realized gains (losses) on derivatives instruments designated as cash flow hedges from the forecasted sale of natural gas produced by the DJ assets and (ii) amounts reclassified from Accumulated other comprehensive loss into earnings when the hedging relationship was discontinued, which included an evaluation of existing authoritative accounting guidance.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers and Corporate Governance

The information called for by Item 10 is incorporated by reference from information under the captions "Corporate Governance," "Meetings and Committees of our Board" and "Compliance with Section 16(a) of the Securities Exchange Act of 1934" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year. Information regarding Executive Officers is contained in this report in Item 1 Business of this Annual Report Form 10-K.

Item 11. Executive Compensation

The information called for by Item 11 is incorporated by reference from information under the caption "Executive Compensation" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information called for by Item 12 is incorporated by reference from information under the captions "Security Ownership" and "Principal Shareholders" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year and Item 5 Market for the Registrant's Common Equity and Related Shareholder Matters and Issuer Purchases of Equity Securities of this Annual Report Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information called for by Item 13 is incorporated by reference from information under the caption "Certain Relationships and Related Transactions" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

Item 14. Principal Accounting Fees and Services

The information called for by Item 14 is incorporated by reference from the information under the caption "Fees to Independent Registered Public Accounting Firms for 2010 and 2009" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

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 Annual Report on Form 10-K.

(b) Exhibits

3.1*	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*	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*	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).
4.2*	Indenture between the Registrant and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.3 to the Registrant's Registration Statement on Form S-3ASR filed on June 15, 2006, File No. 1-9735).
4.3*	First Supplemental Indenture, dated as of October 24, 2006, between the Registrant and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on October 25, 2006, File No. 1-9735).
4.4*	Indenture, dated June 15, 2006, between the Registrant 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)
4.5*	First Supplemental Indenture, dated May 27, 2009, between the Registrant 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)
4.6*	Second Supplemental Indenture, dated November 1, 2010, 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 filed on November 1, 2010, File No. 1-09735)
4.7*	Form of 8^{1}/4% Senior Subordinated Notes due 2016 (included in Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on October 26, 2006, File No. 1-09735).
4.8*	Form of 10^{1}/4% Senior Notes due 2014 (included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on May 29, 2009, File No. 1-09735)
4.9*	Form of 6^{3}/4% Senior Notes due 2020 (included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on November 1, 2010, File No. 1-09735).
4.10*	Second Amended and Restated Credit Agreement dated November 15, 2010 by and among the Company and Wells Fargo Bank, N.A. and other lenders (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed on November 17, 2010, File No. 1-9735).

	Berry and its subsidiaries are party to other debt instruments not filed herewith under which the total amount of securities authorized does not exceed 10% of the total assets of Berry and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, Berry agrees to furnish a copy of such instruments to the SEC upon request.
10.1* **	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).
10.2* **	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).
10.3* **	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)
10.4* **	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).
10.5* **	Crude Oil Purchase Contract dated October 5, 2010 between the Registrant and ExxonMobil Oil Corporation (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the period ended September 30, 2010, File No. 1-9735).
10.6*†	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).
10.7*†	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 filed on June 26, 2006, File No. 1-9735).
10.8*†	Berry Petroleum Company 2005 Equity Incentive Plan (filed as Exhibit 4.2 to the Registrant's Registration Statement on Form S-8 filed on July 29, 2005, File No. 333-127018).
10.9*†	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 Registration Statement on Form S-8 filed on July 29, 2005, File No. 333-127018).
10.10*†	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 Registration Statement on Form S-8 filed on July 29, 2005, File No. 333-127018).
10.11*†	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 filed on June 26, 2006, File No. 1-9735).
10.12*†	Form of Restricted Stock Award Agreement, by and between Registrant and selected directors (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed on December 17, 2007, File No. 1-9735).
10.13*†	Form of Restricted Stock Award Agreement, by and between Registrant and selected officers (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K filed on December 17, 2007, File No. 1-9735).

10.14*†	Form of Award Grant under the Performance Share Award Program for select officers of the Company (filed as Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on March 18, 2010, File No. 1-9735)
10.15*†	Award Grant under the Performance Share Award Program to Robert H. Heinemann (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 18, 2010, File No. 1-9735)
10.16*†	Award Grant under the Performance Share Award Program to David D. Wolf (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on March 18, 2010, File No. 1-9735)
10.17*†	Award Grant under the Performance Share Award Program to Michael Duginski (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on March 18, 2010, File No. 1-9735)
10.18*†	Berry Petroleum Company 2010 Equity Incentive Plan (filed as Exhibit 4.3 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.19*†	Berry Petroleum Company 2010 Equity Incentive Plan—Form of Restricted Stock Unit Agreement (filed as Exhibit 4.4 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.20*†	Berry Petroleum Company 2010 Equity Incentive Plan—Form of Restricted Stock Unit Agreement—Officers (as amended and restated) (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K filed on November 17, 2010, File No. 1-9735).
10.21*†	Berry Petroleum Company 2010 Equity Incentive Plan—Form of Restricted Stock Unit Agreement—Directors (filed as Exhibit 4.6 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.22*†	Berry Petroleum Company 2010 Equity Incentive Plan—Form of Stock Option Agreement (filed as Exhibit 4.7 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.23*†	Berry Petroleum Company 2010 Equity Incentive Plan—Form of Stock Appreciation Rights Agreement (filed as Exhibit 4.8 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.24*†	Berry Petroleum Company 2010 Equity Incentive Plan—Form of Restricted Stock Unit Award Agreement—Officers (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K filed on November 17, 2010, File No. 1-9735).
10.25*†	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).
10.26*†	Non-Employee Director Deferred Stock and Compensation Plan (as amended and restated effective November 19, 2008) (filed as exhibit 10.12 to Registrants' Annual Report on Form 10-K for the period ended December 31, 2009, File No. 1-9735).
10.27*†	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 filed on August 24, 2006, File No. 1-9735).

10.28*†	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 filed on June 26, 2006, File No. 1-9735).
10.29*†	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 filed on June 26, 2006, File No. 1-9735).
10.30*†	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and David D. Wolf (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K/A filed on November 21, 2008, File No. 1-9735)
10.31*†	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and Michael Duginski (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 21, 2008, File No. 1-9735)
10.32*	Instrument for Settlement of Claims and Mutual Release by and among the 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).
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 to the Registrant's Annual Report on Form 10-K for the period ended December 31, 2004, 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 15, 2011 regarding Registrant's reserves estimates.
101.INS***	XBRL Instance Document
101.SCH***	XBRL Taxonomy Extension Schema Document
101.CAL***	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF***	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB***	XBRL Taxonomy Label Linkbase Document
101.PRE***	XBRL Taxonomy Extension Presentation Linkbase Document

* Incorporated by reference.
** Portions of this exhibit have been omitted pursuant to a request for confidential treatment.
*** Furnished herewith.
† Management contract or compensatory plan or arrangement.

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 March 1, 2010.

BERRY PETROLEUM COMPANY

/s/ ROBERT F. HEINEMANN	/s/ DAVID D. WOLF	/s/ JAMIE L. WHEAT
ROBERT F. HEINEMANN *President, Chief Executive Officer and Director*	DAVID D. WOLF *Executive Vice President and Chief Financial Officer* *(Principal Financial Officer)*	JAMIE L. WHEAT *Controller* *(Principal Accounting Officer)*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the dates indicated.

Name	Office	Date
/s/ MARTIN H. YOUNG, JR. Martin H. Young, Jr.	Chairman of the Board, Director	March 1, 2011
/s/ ROBERT F. HEINEMANN Robert F. Heinemann	President, Chief Executive Officer and Director	March 1, 2011
/s/ JOSEPH H. BRYANT Joseph H. Bryant	Director	March 1, 2011
/s/ RALPH B. BUSCH, III Ralph B. Busch, III	Director	March 1, 2011
/s/ WILLIAM E. BUSH, JR. William E. Bush, Jr.	Director	March 1, 2011
/s/ STEPHEN L. CROPPER Stephen L. Cropper	Director	March 1, 2011
/s/ J. HERBERT GAUL, JR. J. Herbert Gaul, Jr.	Director	March 1, 2011
/s/ STEPHEN J. HADDEN Stephen J. Hadden	Director	March 1, 2011

Name	Office	Date
/s/ THOMAS J. JAMIESON		
Thomas J. Jamieson	Director	March 1, 2011
/s/ J. FRANK KELLER		
J. Frank Keller	Director	March 1, 2011
/s/ MICHAEL S. REDDIN		
Michael S. Reddin	Director	March 1, 2011

Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(in thousands, except ratios)

	12/31/10	12/31/09	12/31/08	12/31/07	12/31/06
Pre-tax income from continuing operations	$ 136,492	$ 67,888	$ 190,193	$ 195,616	$ 158,191
Interest expense	66,541	50,738	26,209	17,287	10,247
Capitalized interest	28,321	30,107	23,209	18,104	9,339
Earnings	$ 203,033	$ 118,626	$ 216,402	$ 212,903	$ 168,438
Ratio of earnings to fixed charges	**2.1x**	**1.5x**	**4.4x**	**6.0x**	**8.6x**

For purposes of this table, "earnings" consists of income before income taxes from continuing operations plus fixed charges (excluding capitalized interest). "Fixed charges" consists of interest expense and capitalized interest (for both continuing and discontinued operations).

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-135055, 333-157507 and 333-163743) and Form S-8 (Nos. 333-98379, 333-127018 and 333-167698) of Berry Petroleum Company of our report dated March 1, 2011 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Denver, Colorado
March 1, 2011

Exhibit 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 25, 2011

Berry Petroleum Company
1999 Broadway Street, Suite 3700
Denver, CO 80202

Gentlemen:

We hereby consent to (i) the inclusion of our third party letter report dated February 15, 2011, containing our opinion on the proved reserves attributable to certain properties owned by Berry Petroleum Company, as of December 31, 2010, (ii) the use of and reference to our third party letter report dated February 19, 2010, containing our opinion on the proved reserves attributable to certain properties owned by Berry Petroleum Company, as of December 31, 2009, and our “Appraisal Report as of December 31, 2008 on Certain Properties owned by Berry Petroleum Company” (the Reports) under the captions “Properties” and “Oil and Gas Reserves” in Item 1, “Selected Financial Data” in Item 6, and “Supplemental Information About Oil & Gas Producing Activities (Unaudited)” in Item 8 of the Annual Report on Form 10—K for the fiscal year ended December 31, 2010, of Berry Petroleum Company (the Annual Report); and (iii) the use of and reference to the name DeGolyer and MacNaughton as the independent petroleum engineering firm that prepared the Reports under such items; provided, however, that since the cash-flow calculations in the Annual Report include estimated income taxes not included in the Reports, we are unable to verify the accuracy of the cash-flow values in the Annual Report.

Very truly yours,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, certify that:

1. I have reviewed this report on Form 10-K of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, and its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, 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;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

/s/ Robert F. Heinemann
Robert F. Heinemann
President, Chief Executive Officer and Director

March 1, 2011

Exhibit 31.2

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, David D. Wolf, certify that:

1. I have reviewed this report on Form 10-K of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, 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;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

/s/ David D. Wolf
David D. Wolf
Executive Vice President and Chief Financial Officer

March 1, 2011

Exhibit 32.1

Certification of Chief Executive Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Annual Report of Berry Petroleum Company (the “Company”) on Form 10-K for the period ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert F. Heinemann
Robert F. Heinemann
President, Chief Executive Officer and Director

March 1, 2011

Exhibit 32.2

Certification of Chief Financial Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Annual Report of Berry Petroleum Company (the "Company") on Form 10-K for the period ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David D. Wolf, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ David D. Wolf
David D. Wolf
Executive Vice President and Chief Financial Officer

March 1, 2011

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 15, 2011

Berry Petroleum Company
1999 Broadway
Suite 3700
Denver, Colorado 80202

Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved crude oil, condensate, natural gas liquids (NGL), and natural gas reserves, as of December 31, 2010, of certain properties owned by Berry Petroleum Company (Berry). This evaluation was completed on February 15, 2011. Berry has represented that these properties account for 100 percent on a net equivalent barrel basis of Berry's net proved reserves as of December 31, 2010. The net proved reserves estimates prepared by us have been prepared in accordance with the reserves definitions of Rules 4—10(a) (1)—(32) of Regulation S—X of the Securities and Exchange Commission (SEC) of the United States.

Reserves included herein are expressed as net reserves.Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2010. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Berry after deducting all interests owned by others. Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as that portion of the total gas to be delivered into a gas pipeline for sale after separation, processing, fuel use, and flare. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base of the state in which the interest is located. Condensate reserves estimated herein are those to be recovered by conventional lease separation. NGL reserves are those attributed to the leasehold interests according to pro cessing agreements.

Values shown herein are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net

reserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating expenses, and capital costs from the future gross revenue. Operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization.

Estimates of oil, condensate, NGL, and natural gas should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this evaluation were obtained from reviews with Berry personnel, Berry files, from records on file with the appropriate regulatory agencies, and from public sources. Additionally, this information includes data supplied by Petroleum Information/Dwights LLC; Copyright 2010 Petroleum Information/Dwights LLC. In the preparation of this report we have relied, without independent verification, upon such information furnished by Berry with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principals and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with

similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

Definition of Reserves

Petroleum reserves estimated by us included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by us in this report are in accordance with the reserves definitions of Rules 4—10(a) (1)—(32) of Regulation S—X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including

consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves—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.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves—Developed oil and gas reserves are reserves of any category 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 atthe time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves—Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4—10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Primary Economic Assumptions

The following economic assumptions were used for estimating existing and future prices and costs:

Oil,Condensate, and NGL Prices

Berry has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Berry supplied differentials by certain geographic producing areas to a NYMEX Light Crude Oil reference price of $79.43 per barrel and the prices were held constant thereafter. The volume-weighted average oil price was $71.19 per barrel and the volume-weighted average NGL price was $39.72 per barrel.

Natural Gas Prices

Berry has represented that the natural gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Berry supplied differentials by certain geographic producing areas to the NYMEX Natural Gas reference price of $4.39 per million British thermal units. The prices were held constant thereafter. The volume-weighted average price was $4.57 per Mcf.

Operating Expenses and Capital Costs

Operating expenses and capital costs, based on information provided by Berry, were used in estimating future costs required to operate the properties. In certain cases, future costs, either higher or lower than existing costs, may have been used because of anticipated changes in operating conditions. These costs were not escalated for inflation.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2010, estimated oil and gas volumes. The reserves estimated in this report can be produced under current regulatory guidelines.

Our estimates of Berry's net proved reserves attributable to the reviewed properties are based on the definitions of proved reserves of the SEC and are as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Net Proved Reserves as of December 31, 2010			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved Developed				
California	76,199	0	0	76,199
Colorado	206	0	75,097	12,722
Nevada	685	0	0	685
Texas	3,057	2,118	164,071	32,520
Utah	5,821	831	29,365	11,546
Wyoming	0	0	33	6
Total Proved Developed	**85,968**	**2,949**	**268,566**	**133,678**

Proved Undeveloped				
California	41,060	0	0	41,060
Colorado	658	0	251,235	42,531
Nevada	0	0	0	0
Texas	19,261	7,477	90,715	41,857
Utah	7,867	941	19,676	12,087
Wyoming	0	0	0	0
Total Proved Undeveloped	**68,846**	**8,418**	**361,626**	**137,535**
Total Proved	**154,814**	**11,367**	**630,192**	**271,213**

Note: Gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent

The estimated future revenue attributable to Berry's interests in the proved reserves, as of December 31, 2010, of the properties appraised is summarized as follows, expressed in thousands of dollars (M$):

	Developed Producing	Developed Nonproducing	Undeveloped	Total
Future Gross Revenue, M$	5,771,587	1,570,777	7,012,263	14,354,627
Production and Ad Valorem Taxes, M$	176,526	52,565	302,850	531,941
Operating Expenses, M$	1,897,278	371,316	1,645,648	3,914,242
Capital Costs, M$	151,827	94,125	1,543,049	1,789,001
Future Net Revenue*, M$	3,545,956	1,052,771	3,520,716	8,119,443
Present Worth at 10 Percent*, M$	2,001,726	486,839	1,345,612	3,834,177

* Future income tax expenses were not taken into account in the preparation of these estimates.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9,932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries—Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4—10(a) (1)—(32) of Regulation S—X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S—K of the Securities and Exchange Commission; provided, however, fu ture income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Berry. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Berry. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Paul J. Szatkowski, P.E.
Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton

[SEAL]

CERTIFICATE of QUALIFICATION

I, Paul J. Szatkowski, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Berry dated February 15, 2011, and that I, as Senior Vice President, was responsible for the preparation of this report.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in 1974; that I am a Registered Professional Engineer in the State of Texas;that I am a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists; and that I have in excess of 36 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Paul J. Szatkowski, P.E.

Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton

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