BERRY PETROLEUM CO
Form 10-K
February 25, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

x Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2009
Commission file number 1-9735

BERRY PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

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

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

Registrant's telephone number, including area code:
(303) 999- 4400
Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES x NO o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
YES o NO x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every
Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the
preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES x 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 filerx Accelerated filero Non-accelerated filero Smaller reporting companyo

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

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

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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PART I

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Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this 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," "
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 on page 17 in Part I, Item 1A in this Form 10-K filed with the Securities and Exchange Commission, under the heading "Risk Factors."

PART I

Item 1. Business

General

We are an independent energy company engaged in the production, development, acquisition, exploitation of and exploration for, crude oil and natural gas. While 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. In 2003, we purchased and began operating properties in the Rocky Mountains. In 2008, we purchased and began operating properties in East Texas (E. Texas) and in 2010 we expect to enter the Permian basin in West Texas (W. Texas). Our corporate headquarters are located in Denver, Colorado and we have regional offices in Bakersfield, California and Plano, Texas. Information contained in this report on Form 10-K reflects our business during the year ended December 31, 2009 unless noted otherwise.

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.

We operate in one industry segment, which is the production, development, acquisition, exploitation of and exploration for, 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 "Financial Statements and Supplementary Data" for financial information about this industry segment.

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 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. At our mature South Midway-Sunset Field, we continue to add horizontal wells and additional steam flooding capacity to maintain and increase production levels. In addition, since we acquired our Poso Creek assets in 2003, we have successfully completed thermal EOR redevelopment to increase production from under 50 BOE/D at acquisition to average production of 3,200 BOE/D in 2009.

Grow Oil Production from our Inventory of Organic Development Projects. We have a proven track record of developing reserves through enhanced recovery projects, as well as entering into new hydrocarbon basins. For example, in our North Midway diatomite, production averaged 3,100 BOE/D in 2009 and we expect to exit 2010 at 5,000 BOE/D and continue to grow the asset significantly over the next several years. We plan to continue our focus on low-risk development of our existing assets rather than exploration.

Increase Natural Gas Production that will Meet the Growing Demand for Steam Generation. Our assets in E. Texas, Piceance and Uinta basins produce natural gas that offsets our consumption of natural gas utilized to generate steam used in our EOR activities. We intend to continue to increase production from these assets as we focus on additional enhanced oil development projects that we expect will require increasing quantities of natural gas for steam generation.

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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/or 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, but we also may obtain alternative sources of capital investment to develop our assets through partnerships, joint ventures or other investment opportunities with third parties. We hedge a portion of our production and utilize long-term sales contracts whenever possible 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 in our core areas of expertise. This strategy allows us to leverage our operating and technical expertise and build on established core operations. We will continue to review asset acquisitions that meet our economic criteria with a primary focus on large repeatable oil development potential in these regions. We will also continue to evaluate natural gas properties, primarily in our core areas of operation, which can be developed at reasonable costs.

Business Strengths

Balanced High Quality Asset Portfolio. Since 2002, we have grown our asset base and diversified our California heavy oil through acquisitions in the Permian basin, Rocky Mountains and E. Texas regions that have significant growth potential. Our diverse asset base provides us with the flexibility to reallocate capital among our assets depending on fluctuations in natural gas and oil 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 21 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. Our California assets have an average depth of less than 2,000 feet and are located in areas where we are an established producer. Our E. Texas Assets provide us with the opportunity for repeatable development of multiple stacked reservoirs in the Travis Peak, Cotton Valley and Bossier sands and in the Haynesville shale. In the Permian basin we expect to begin drilling in 2010 to multiple targets including the Spraberry, Dean, Wolfcamp and Strawn formations on 40-acre spacing. Our historical drilling success rate for the three years ended December 31, 2009 averaged 99%.

Operational control and financial flexibility. We exercise operating control over more than 95% 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 have broad industry experience, including experience in heavy oil thermal recovery operations and tight gas sands 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.

Acquisition and Divestiture Activities

We pursue acquisitions that meet our criteria for investment returns and that are consistent with our corporate strategy, and seek to divest certain properties from time to time that do not fit or complement our strategic growth plan.

On January 8, 2010, we entered into an agreement to acquire certain properties primarily in the Wolfberry trend in W. Texas from a private seller for total cash consideration of $126 million. At December 31, 2009, the properties included total proved reserves of 11.2 MMBOE, of which 85% were crude oil and 23% were proved developed. We expect to close in the first quarter of 2010, subject to customary closing conditions. We have identified over 130 drilling locations on forty acre spacing in the Wolfberry trend targeting the Spraberry, Dean, Wolfcamp and Strawn formations.   We plan to test twenty acre down spacing in late 2010, which would provide an additional 150 drilling locations on twenty acre spacing. We would operate approximately 70% of, and would have an average 68.5% working interest (54.1% net revenue interest) in, the properties to be acquired in the Wolfberry trend.

On April 1, 2009 we sold our DJ basin assets and related hedges for $154 million before customary closing adjustments.

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

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In May 2007, we sold our West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million, including post closing adjustments.

Properties

The following table provides information regarding our operations by area as of December 31, 2009:

Name, State	% Average Working Interest	Total Net Acres	Proved Reserves (MMBOE) (1)	Proved Developed Reserves (MMBOE)	% of Total Proved Developed Reserves		Proved Undeveloped Reserves (MMBOE)	% of Total Proved Undeveloped Reserves	
S. Midway, CA	98	3,062	59.6	49.5	39	%	10.1	9	%
N. Midway, CA	100	2,230	52.2	26.4	21		25.8	23	
Uinta, UT	98	36,636	22.9	9.8	8		13.1	12	
E. Texas	99	4,508	40.0	27.3	22		12.7	12	
Piceance, CO	55	3,157	60.6	12.5	10		48.1	44	
Totals		49,593	235.3	125.5	100	%	109.8	100	%

(1) MMBOE – Million BOEs

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. Our S. Midway asset team is primarily focused on production and generates significant cash flow to fund our planned drilling inventory in our N. Midway, Piceance, E. Texas and Uinta projects.

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. We have planned a five-year, 150-well drilling program at Ethel D to develop the significant undeveloped reserves remaining on this asset. In 2008, we added 20 horizontal wells below existing horizontal wells at the South Midway-Sunset Field, and we further developed Ethel D by drilling 32 producers and initiating a pilot steam flood. In 2009 we drilled 19 horizontal wells and 18 vertical producers at the South Midway-Sunset Field. These wells have been placed deeper and closer to the oil-water contact. All of these wells are currently on production and are performing in line with expectations. We also accelerated our continuous steam support for these horizontal wells by drilling six vertical steam injectors. At Ethel D we have been encouraged by the performance of our steam flood pilots and expanded the flood in the fourth quarter of 2009. In 2010 at Homebase and Formax we will be completing our horizontal drilling program and expanding the continuous steam injection project by drilling 15 horizontal wells and 10 vertical steam injectors. Capital will also be focused on further thermal development at Ethel D by drilling 24 producers.

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 3,200 BOE/D in 2009. In 2009, we expanded the steam flood by drilling eight new injectors. To provide steam to these wells we also installed a fifth steam generator. In 2010 we will continue to expand the steam flood at Poso Creek drilling 10 producers and three steam flood injectors.

N. Midway – In 2009, total proved reserves from the N. Midway diatomite asset were 35.3 MMBOE, representing a 15% increase from 2008. In 2008, total proved reserves and production from the N. Midway diatomite asset were

30.6 MMBOE and 0.7 MMBOE, respectively, representing an increase from 2007 of 162% in proved reserves and 86% in production. We expect significant proved reserve additions from this asset. In 2008, we drilled approximately 85 diatomite wells, completed major infrastructure upgrades that will support future development, increased steam injection and further refined our thermal recovery techniques. 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. During the fourth quarter of 2009, we initiated a four-pattern steam flood pilot on our recently acquired McKittrick property. In 2010, capital will be focused on drilling an additional 100 diatomite wells, major infrastructure upgrades that will support future development, increasing steam injection, and further refining our thermal recovery techniques. In addition, capital will be invested in the initiation of four-pilot steam floods at McKittrick, N. Midway, and Placerita.

Permian – On January 8, 2010, we entered into an agreement to acquire certain properties primarily in the Wolfberry trend in W. Texas from a private seller for total cash consideration of $126 million. At December 31, 2009, we estimate that the properties included total proved reserves of 11.2 MMBOE, of which 85% were crude oil and 23% were proved developed. We expect to close in the first quarter of 2010, subject to customary closing conditions. We have identified over 130 drilling locations on forty acre spacing in the Wolfberry trend targeting the Spraberry, Dean, Wolfcamp and Strawn formations. We plan to test twenty acre down spacing in late 2010 which would provide an additional 150 drilling locations on twenty acre spacing. We would operate approximately 70% of, and would have an average 68.5% working interest (54.1% net revenue interest) in, the properties acquired in the Wolfberry trend.

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Uinta – In 2003, we established our initial acreage position in the Uinta basin, targeting the Green River formation that produces both light oil and natural gas. We acquired the Brundage Canyon leasehold in Duchesne County, northeastern Utah, which consists of working interests in approximately 55,000 gross acres which include federal, tribal and private leases. In 2004, we acquired working interests in approximately 163,000 gross acres in the Lake Canyon project, which is located immediately west of our Brundage Canyon producing properties. Total production in Uinta averaged 4,929 BOE/D in 2009 compared to 6,142 BOE/D in 2008. In 2008, we drilled 51 gross (50 net) wells, which included 47 wells at Brundage Canyon, including eight Ashley Forest wells, and four Green River wells at Lake Canyon. In 2009, capital was primarily directed at facility upgrades, pursuing the remaining three Lake Canyon completions, and the Ashley Forest Environmental Impact Study (EIS). Implementation of a water flood pilot in Brundage Canyon had initial start up in the beginning of the fourth quarter of 2009. While the Ashley Forest Development EIS continues to progress with approval now expected in 2010, we obtained a category exemption for 25 wells in the Ashley Forest. In 2010, we plan to run a one rig program in the Uinta basin focused toward developing areas of higher oil potential.

E. Texas – In 2008, we acquired certain interests in natural gas producing properties in the E. Texas Cotton Valley on 4,500 net acres in Limestone and Harrison Counties for approximately $668 million in cash. The E. Texas assets established a core area in a low risk repeatable area and provided an inventory of drilling and recompletion projects. In Limestone County, we are targeting seven productive sands including the Cotton Valley and Bossier sands at depths between 8,000 and 13,000 feet. In Harrison County, we are targeting five productive sands and Haynesville Shale with average depths between 6,500 and 13,000 feet. Production from our E. Texas Assets averaged 24 MMcf/D in 2009. We currently operate a one rig program, and we began drilling our first horizontal Haynesville well in Harrison County in the fourth quarter of 2009. During 2009 we drilled 11 vertical wells in E. Texas. In 2010, we plan to run a one rig program to horizontally drill in the Haynesville Shale in Harrison County.

Piceance – We have two properties in the Piceance basin in Colorado 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 and a net operating working interest of 95% in 4,300 gross acres and a 5% non-operating working interest on 6,300 gross acres on our North Parachute Ranch property. We have accumulated a sizable resource base which should allow us to add significant proved reserves over the next several years. Total production in Piceance averaged 19 MMcf/D during 2009 and 20.8 MMcf/D in 2008. We operated a four rig drilling program for most of 2008 and drilled 54 gross (27 net) wells at Garden Gulch and 18 gross (17 net) wells at North Parachute. Significant progress was made during 2008 in reducing the days required to drill wells. By the end of 2008, the number of drilling days averaged 10 days on Garden Gulch and 11 days in North Parachute, a 40% reduction in drilling times compared to early 2008. During 2009, we began a 20 well completion program testing new completion designs and have seen encouraging results in line with our expectations. During 2009 we added water handling infrastructure which reduced our operating costs in the Piceance basin. "See Item 1A. Risk Factors – We may be unable to meet our drilling obligations" for a discussion of our drilling obligations relating to our Piceance basin properties. In 2010, we plan to run a one rig program.

Reserves

The following table shows our total estimated net proved reserves at December 31, 2009:

Net proved reserves:	2009
Proved Developed:	
Oil (MBbl)(1)	82,870
Natural Gas (Mmcf)(2)	255,520
Total (MBOE)(3)	125,456
Proved Undeveloped	
Oil (MBbl)	47,070

Natural Gas (Mmcf)	376,658
Total (MBOE)	109,847
Total Proved:	
Oil (MBbl)	129,940
Natural Gas (Mmcf)	632,178
Total (MBOE)	235,303

(1) MBbl – Thousand barrels
(2) Mmcf – Thousand Mcfs
(3) MBOE – Thousand BOEs (6 Mmcf : 1 MBOE)

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During 2009, we invested approximately $93 million in the conversion of proved undeveloped reserves to proved developed reserves. We converted approximately 7 MMBOE of proved undeveloped reserves to proved developed reserves during 2009. At December 31, 2009, less than 1% of our proved undeveloped reserves in individual fields remained undeveloped for five years or more. We estimate these reserves will be developed over the next three years.

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 product prices or development and production expenses, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates. 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. for the years ended December 31, 2009, 2008 and 2007. We engaged DeGolyer and McNaughton (D&M) to prepare 100% our proved oil and gas reserve estimates and the 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 accepted 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 natural gas and oil calculated as the un-weighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period 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 DeGoyler and MacNaughton dated February 19, 2010.

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 internal 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 that we operate and has supervised operations in a majority of them. The ending reserves are also subject to multiple levels of management review.

Sensitivity of Reserves to Prices.

A significant portion of our operating costs in California are based on the price of natural gas. The requirement to use year-end costs may impact the present value of estimated future cash flows before income taxes discounted at 10%

(PV10), if the un-weighted average first-day-of-the-month natural gas price is higher or lower than the year-end price of natural gas. We believe it would be meaningful to consider price sensitivities to the proved reserve calculation as follows:

	Oil (MBbl)	Natural Gas (Mmcf)	Total MBOE	Pre-Tax PV10 (1) ($ in millions)
SEC Proved Reserves (2)	129,940	632,178	235,303	1,849
Steam Injection Cost Alternative (3)	130,091	632,188	235,455	2,106

(1) Pre-tax PV10 may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows (SMOG), which is the most directly comparable GAAP financial measure. Pre-tax PV10 is computed on the same basis as the SMOG but without deducting future income taxes. We believe pre-tax PV10 is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV10 as a basis for comparison of the relative size and value of our reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10 is not a substitute for the SMOG. Our pre-tax PV10 and the SMOG do not purport to present the fair value of our oil and natural gas reserves. The following table shows the reconciliation of SMOG to the pre-tax PV10 value.

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	SEC Proved Reserves	Steam Injection Cost Alternative
SMOG	1,446	1,611
Discounted future cash flow from income taxes	403	495
Discounted future net cash flow before income taxes (PV10)	1,849	2,106

(2) SEC proved reserves have been calculated in accordance with current authoritative guidance.

(3) Steam injection cost alternative assumptions were based on using the un-weighted arithmetic average of the first-day-of-the-month price for each month during the calendar year for the basis of determining our steam injection costs, as compared to using the end of the year natural gas price to determine our steam injection costs.
The 2009 year end natural gas price used to calculate steam costs was $6.20/Mcfe compared to the 2009 un-weighted arithmetic average of the first-day-of-the-month natural gas price of $3.93/Mcfe. All other inputs and assumptions remain the same as those used in calculating the SEC proved reserves.

Operations. In California, we operate all of our principal oil and gas producing properties. The California assets consist of heavy crude oil which requires heat, supplied in the form of steam, which is 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. Field operations related to oil production include the initial recovery of the crude oil and its transport through treating facilities into storage tanks. After the treating process is completed, which includes removal of water and solids by mechanical, thermal and chemical processes, the crude oil is metered through automatic custody transfer units or gauged before sale and subsequently transferred into crude oil pipelines owned by other companies or transported via truck.

In the Rocky Mountains, crude oil produced from the Uinta properties is transported by truck. Natural gas produced from the Uinta and Piceance properties is transported to one of several main pipelines. We have firm transportation contracts on two different pipelines to provide transport for our Rocky Mountain natural gas production. In E. Texas, natural gas produced from the Darco and Oakes properties is transported intra-state on the Enbridge system to various market points. See Firm Transportation Summary on page 9.

Crude Oil and Natural Gas Marketing

Economy. Oil is a globally priced commodity and is priced according to the supply and demand of crude oil and its products. The range of NYMEX light sweet crude prices for 2009, based upon settlements, was a low of $33.98 and a high of $81.37.

	2009	2008	2007
Average NYMEX settlement price for WTI	$ 62.09	$ 99.75	$ 72.41
Average posted price for:			
Utah 40 degree API black wax (light) crude oil	49.84	84.99	59.28
California 13 degree API heavy crude oil	53.54	86.51	61.64
Average crude price differential between WTI and:			
Utah light 40 degree API black wax (light) crude oil	12.25	14.76	13.13
California 13 degree API heavy crude oil	8.55	13.24	10.77

The above posting prices and differentials do not necessarily reflect the amounts paid or received by us due to the contracts discussed below. In California the differential on December 31, 2009 was $7.96 and ranged from a low of $5.20 to a high of $14.02 per barrel during the year. In Utah the differential on December 31, 2009 was $11.00 and ranged from a low of $10.00 to a high of $16.00 per barrel during the year, based on oil postings.

Oil Contracts. We market our crude oil production to competing buyers which may be independent or major oil refiners or third party marketers.

As of December 31, 2009, we have over 90% of our California oil production under contract with major oil producers through the third quarter of 2010. The remaining oil production is under contract over a long-term period with a niche refinery in the Los Angeles basin.

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 our 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 our Uinta properties averaged approximately 2,700 Bbl/D in 2009. Please see "Item 1A. Risk Factors–We may not be able to deliver minimum crude oil volumes required by our sales contract."

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Natural Gas Marketing. We market our produced natural gas from Colorado, Utah and Texas. Generally, natural gas is sold at monthly index related prices. At some locations we utilize intrastate or interstate pipeline transportation to move the gas to a more favorable market point. Certain volumes are sold at a daily spot related price. As of mid-2009, the pricing of our Rocky Mountain natural gas production is tied to the eastern markets in Lebanon or Clarington Ohio. Also beginning in early 2009, the E. Texas natural gas is generally priced off the Florida Zone 1 index. Utah gas pricing remained unchanged and is generally sold on a Questar related index price.

	2009	2008	2007
Annual average closing/index price per MMBtu for:			
NYMEX Henry Hub (HH) prompt month natural gas contract last day	$ 3.99	$ 9.03	$ 6.86
Rocky Mountain Questar first-of-month indices (Uinta sales)	3.02	6.15	3.69
Rocky Mountain CIG first-of-month indices (WY and former Piceance sales)	3.07	6.24	3.97
Mid-Continent PEPL first-of-month indices (former Piceance sales)	3.24	7.08	5.99
Eastern Market Lebanon, Ohio first-of-month indices (Aug 2009 – Dec 2009)	3.77	n/a	n/a
Texas Eastern – E. Texas first-of-month indices	3.58	8.46	n/a
Florida Zone 1 first-of-month indices (E. Texas sales)	3.87	n/a	n/a
Average natural gas price per MMBtu differential between NYMEX HH and:			
Questar	0.97	2.88	3.17
CIG	0.92	2.79	2.89
PEPL	0.75	1.95	.87
Lebanon (Aug 2009 – Dec 2009)	(0.03)	n/a	n/a
Texas Eastern – E. Texas	0.41	0.57	n/a
Florida Zone 1	0.12	n/a	n/a

Gas Basis Differential. We have contracted a total of 35,000 MMBtu/D on the Rockies Express Pipeline (REX) under two separate transactions to provide firm transport for our Piceance gas production. Upon the start-up of REX in mid-2009, the sales point for our Piceance natural gas moved from the Rockies to the Mid-Continent under REX West and finally to the eastern Ohio market with REX East. By year-end 2009, the Piceance natural gas was selling at, or above, Henry Hub. The bulk of the Uinta basin gas continues to sell on a Questar index related price. Early in 2009, Enbridge Pipeline completed its expansion to Orange County, TX. Since that time, the majority of the E. Texas natural gas has been sold with a price related to the Florida Zone 1 index.

We have physical access to interstate gas pipelines to move gas to or from market. To assure delivery of gas, we have entered into long-term gas transportation contracts as follows:

Firm Transportation Summary.

Pipeline	From	To	Quantity (Avg. MMBtu/D)	Term	December 31, 2009 demand charge per MMBtu		Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$ 0.5847		$ 8,544
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 2/2018	1.1134	(1)	84,561
	Meeker, CO	Clarington, OH	10,000		1.094	(1)	32,528

Rockies Express Pipeline				1/2008 to 1/2018			
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,500	9/2003 to 4/2012	0.1739		370
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,859	9/2003 to 9/2012	0.1739		499
Questar Pipeline	Brundage Canyon, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.2573		6,022
Enbridge Pipeline	Limestone and Harrison Counties, TX	Orange, TX	Up to 55,000	4/2009 to 3/2012	0.22		4,351
Total			112,359			$	136,875

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

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Steaming Operations

Cogeneration Steam Supply. As of December 31, 2009, approximately 48% of our proved reserves, or 112 million barrels, consisted of heavy crude oil produced from depths of less than 2,000 feet. 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 26 fully permitted conventional boilers. The quantity of boilers operated at any point in time is dependent on 1) the steam volume required for us to achieve our targeted production and 2) the price of natural gas compared to the realized price of crude oil sold.

Total barrels of steam per day (BSPD) capacity as of December 31, 2009 is as follows:

Steam generation capacity of conventional boilers	107,292
Steam generation capacity of cogeneration plants	42,789
Additional steam purchased under contract with a third party	2,050
Total steam capacity	152,131

The average volume of steam injected for the years ended December 31, 2009 and 2008 was 109,153 BSPD and 99,908 BSPD, respectively.

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.

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.

As of December 31, 2009, approximately 78% of the volume of natural gas purchased to generate steam and electricity is 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 22% 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 Rocky Mountain Northwest Pipeline (NWPL) index.

	2009	2008	2007
Average SoCal Border Monthly Index Price per MMBtu	$ 3.59	$ 7.92	$ 6.38
Average Rocky Mountain NWPL Monthly Index Price per MMBtu	3.09	6.25	3.95
Average PG&E Citygate Monthly Index Price per MMBtu	4.17	8.63	6.86

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 2009 and estimated average 2010 amount of production in excess of consumption and hedged volumes (in average MMBtu/D):

	2009	Estimated 2010
Approximate natural gas volumes produced in operations	62,000	65,000
Approximate Natural gas consumed:		
Cogeneration operations	27,000	27,500
Conventional boilers (1)	24,000	34,500
Total natural gas volumes consumed in operations	51,000	62,000
Less: Our estimate of approximate natural gas volumes consumed to produce electricity (2)	(20,800)	(19,900)
Total approximate natural gas volumes consumed to produce steam	30,200	42,100
Natural gas volumes hedged	14,000	19,000
Amount of natural gas volumes produced in excess of volumes consumed to produce steam and volumes hedged	17,800	3,900

(1) In 2009, we added conventional capacity at our Poso Creek and N. Midway diatomite assets to increase our production from these fields.
(2) 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 92 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 the 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 boilers. 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. Historically, we have sold electricity produced by our cogeneration facilities, each of which is a Qualifying Facility (QF) under the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA), 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; and 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 the outcome of global settlement discussions to resolve this and other QF related matters. We do not expect the prospective reduction in electricity revenue as a result of lower SRAC prices to be material to the Company.

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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. Effective upon their scheduled termination, each of the three contracts was extended pursuant to the SRAC Decision, for the terms described below. Pursuant to these contracts, we are paid the purchasing utility's SRAC energy price and a capacity payment that is subject to adjustment from time to time by the CPUC, as they did in the SRAC decision. Edison and PG&E challenged, in the California Court of Appeals, the legality of the CPUC decision that ordered the utilities to enter into these five-year SO1 contracts, and similar one-year SO1 contracts that were ordered for 2004. The Court ruled that the CPUC had the right to order the utilities to execute these contracts. The Court also ruled 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 the requirements of PURPA. A CPUC proceeding to resolve this retroactive price issue is being held in abeyance pending the outcome of global settlement discussions to resolve this and other QF related matters. Our SO2 contract for the Placerita Unit 1 Facility expired on March 25, 2009. Effective upon its expiration, Berry executed an amendment with Edison to extend the non-price terms of the SO2 pursuant to the SRAC Decision until a replacement contract is approved by the CPUC and is available for execution by Berry. The payment provisions of this extension agreement reflect the payment provisions ordered in the SRAC Decision. The capacity price was reduced upon the expiration of the SO2 and the SRAC energy price was reduced effective August 1, 2009. The Company intends to enter into new SO contracts with Edison and PG&E for all three facilities as soon as the ongoing challenges are resolved and the CPUC has approved the terms of the new SO contracts.

During the California energy crisis in 2000 and 2001, we had electricity sales contracts with various utilities 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. Please 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)	16	4	6,500
S. Midway						
Cogen 18	SO1	PG&E	Dec-10 (2)	11	4	6,400
Cogen 38	SO1	PG&E	Dec-10 (2)	37	-	18,000

(1) The term of this agreement was extended until the CPUC approves a replacement contract.
(2) This agreement will terminate earlier upon CPUC approval of a replacement contract.

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 (identified on page 4).

Employees. On December 31, 2009, we had 243 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 is good.

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Capital Expenditures Summary (Excluding Acquisitions).

The following is a summary of the developmental capital expenditures incurred during 2009 and 2008 and estimated capital expenditures for 2010 (in thousands):

	2010 (Estimated) (1)	2009	2008
S. Midway Asset Team			
New wells and workovers	$ 19,000	$ 18,000	$ 44,000
Facilities - oil & gas	22,000	6,000	10,000
Facilities – cogeneration	-	-	1,000
General	-	-	-
	41,000	24,000	55,000
N. Midway Asset Team			
New wells and workovers	40,000	14,000	33,000
Facilities - oil & gas	37,000	18,000	34,000
Facilities – cogeneration	3,000	-	3,000
General	1,000	-	-
	81,000	32,000	70,000
Permian Asset Team			
New wells and workovers	30,000	-	-
	30,000	-	-
Uinta Asset Team			
New wells and workovers	33,000	4,000	57,000
Facilities	2,000	1,000	2,000
General	-	1,000	-
	35,000	6,000	59,000
E. Texas Asset Team			
New wells and workovers	51,000	41,000	66,000
Facilities	-	5,000	-
General	-	1,000	-
	51,000	47,000	66,000
Piceance Asset Team			
New wells and workovers	30,000	21,000	124,000
Facilities	6,000	4,000	5,000
General	-	1,000	1,000
	36,000	26,000	130,000
DJ Asset Team	-	-	17,000
Other Fixed Assets	1,000	-	1,000
TOTAL	$ 275,000	$ 135,000	$ 398,000

(1) Estimated capital expenditures may be adjusted for numerous reasons including, but not limited to, oil and natural gas price levels and equipment availability, working capital needs, permit and regulatory issues.

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Production, Average Sales Prices, and Production Costs. The following table reflects production, average sales price, and production cost information for the years ended December 31, 2009, 2008 and 2007:

	2009	2008	2007
Net annual production: (1)			
Oil (Mbbl)	7,186	7,441	7,210
Gas (MMcf)	22,657	25,559	15,657
Total equivalent barrels (MBOE) (2)	10,962	11,700	9,819
Less DJ Production (MBOE) (2)	279	1,206	1,140
Production – Continuing operations (MBOE) (2)	10,683	10,494	8,679
Average sales price for continuing operations:			
Oil (per Bbl) before hedging	$ 50.73	$ 86.90	$ 57.85
Oil (per Bbl) after hedging	57.28	70.01	53.24
Gas (per Mcf) before hedging	3.61	6.91	4.17
Gas (per Mcf) after hedging	4.09	7.11	5.48
Per BOE before hedging	41.23	73.64	52.30
Per BOE after hedging	46.59	62.03	49.80
Oil and gas production (per BOE) costs for continuing operations	14.66	17.99	15.09

Mbbl - Thousands of barrels
Mcf - Thousand cubic feet
MMcf - Million cubic feet
BOE - Barrels of oil equivalent
MBOE - Thousand barrels of oil equivalent

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

(2) Equivalent oil and gas information is at a ratio of 6 thousand cubic feet (Mcf) of natural gas to 1 barrel (Bbl) of oil. A barrel of oil is equivalent to 42 U.S. gallons

Acreage and Wells. As of December 31, 2009, our properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres (1)		Total	
	Gross (2)	Net (2)	Gross	Net	Gross	Net
California	5,317	5,292	1,240	1,240	6,557	6,532
Colorado	6,314	3,157	11,691	8,714	18,005	11,871
Kansas	-	-	62,810	61,856	62,810	61,856
Texas	4,794	4,523	-	-	4,794	4,523
Utah	39,280	36,635	220,905	101,878	260,185	138,513
Wyoming	3,520	539	1,746	276	5,266	815
Other	40	3	-	-	40	3
	59,265	50,149	298,392	173,964	357,657	224,113

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

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

The following table summarizes gross and net productive oil and natural gas wells at December 31, 2009. Gross wells represent the total number of wells in which we have a working interest. Net wells represent the number of gross wells multiplied by the percentages of the working interests owned by us. One or more completions in the same bore hole are counted as one well.

	Productive Wells	
	Gross	Net
Oil	2,385	2,348
Natural Gas	524	350
Total	2,909	2,698

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Drilling Activity. The following table sets forth certain information regarding our drilling activities for the periods indicated:

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development wells drilled:						
Productive	132	132	443	374	411	314
Dry (1)	2	2	6	5	7	5
Exploratory wells drilled:						
Productive	-	-	3	2	5	3
Dry (1)	-	-	-	-	-	-
Total wells drilled:						
Productive	132	132	446	376	416	317
Dry (1)	2	2	6	5	7	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.

	2009	
	Gross	Net
Total productive wells drilled:		
Oil	121	121
Gas	11	11

We drilled 134 gross (134 net) wells during 2009, realizing a gross success rate of 99 percent. As of December 31, 2009, we have 2 rigs drilling on our properties under long-term contracts. As of December 31, 2009, we had 3 gross (3 net) wells in progress.

The following table sets forth certain information regarding drilling activities by area for the year ended December 31, 2009:

	Gross Wells	Net Wells
S. Midway	57	57
N. Midway	64	64
Uinta	2	2
Texas	11	11
Totals (1)	134	134

(1) Includes 2 wells that were dry holes in 2009.

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 Piceance. Two of these rigs are not currently drilling and one rig is drilling in the Uinta basin. As the rig market and our rig requirements change, we continue to evaluate the ownership of these rigs. We recorded impairment charges of $4.2 million in both 2009 and 2008 related to the disposal and impairment of our drilling rigs and related equipment. See Note 6 to the financial statements.

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.

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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 drilling 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 PURPA, as amended, and the adoption of regulations thereunder 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 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 amends 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. Such a determination has not been made for our service areas in California. 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.

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Item 1A. Risk Factors

Other Factors Affecting the Company's Business and Financial Results

Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business, results of operations and financial condition. Our revenues, profitability and future growth and reserve calculations depend substantially on the price received for our oil and gas production. These prices also affect the amount of our cash flow available for capital expenditures, working capital and payments on our debt, 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 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.

We have a substantial amount of debt and the cost of servicing that debt could limit our financial flexibility and adversely affect our business. We have a substantial amount of indebtedness. At December 31, 2009, we had total long-term outstanding debt of approximately $1.02 billion and no short-term debt. Our borrowing base under our senior secured revolving credit facility is currently approximately $938 million and, as of December 31, 2009, we had approximately $372 million (excluding $4 million of outstanding letters of credit) outstanding under our senior secured revolving credit facility, with additional borrowing availability of approximately $562 million.

We have demands on our cash resources, including, among others, operating expenses and interest and principal payments under our senior secured revolving credit facility, our senior secured money market line of credit, our 10.25¼% senior notes and our 8.25% senior subordinated notes. Our level of indebtedness relative to our proved reserves and these significant demands on our cash resources could have adverse effects on our business. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to our debt;

- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- require us to make principal payments under our senior secured revolving credit facility if the quantities of proved reserves attributable to our crude oil and natural gas properties are insufficient to support our level of borrowings under that credit facility;
- limit our flexibility in planning for, or reacting to, changes in the oil and gas industry;
- place us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds, pay dividends, make certain investments and issue equity on favorable terms or at all;

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- increase our interest expense if interest rates increase, because borrowings under our senior secured revolving credit facility are at a variable rate of interest, and borrowings under our senior secured money market line of credit are generally at a variable rate of interest;

- increase our vulnerability to general adverse economic and industry conditions; and

- result in an event of default upon a failure to comply with financial covenants contained in our senior secured revolving credit facility, senior secured money market line of credit, senior subordinated notes or senior notes which, if not cured or waived, could have a material adverse effect on our business, financial condition or results of operations.

A higher level of indebtedness increases the risk that we may default on our obligations. Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon our future performance and our ability to refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital markets conditions, oil and natural gas prices, our financial condition, results of operations and prospects and other factors, many of which are beyond our control.

The borrowing base under our credit facility may be reduced below the amount of our outstanding borrowings under that facility. The amount we are able to borrow under our senior secured revolving credit facility is determined based on the value of our proved oil and natural gas reserves and is based on oil and natural gas price assumptions which vary by individual lender. Our borrowing base is subject to redetermination twice each year in April and October with the option for one additional redetermination each year and additional redeterminations contemporaneously with any issuance of permitted second lien debt and after any issuance of permitted unsecured debt. Each dollar of permitted senior unsecured debt automatically reduces the borrowing base under our senior secured revolving credit facility by 25 cents. Should there be a deficiency in the amount of our borrowing base in comparison to our outstanding debt under the senior secured revolving credit facility, we would be required to repay any such deficiency in two equal installments, 90 and 180 days after the redetermination. If we were unable to make those repayments, we would be in default under our senior secured revolving credit facility, which could have a material adverse effect on our business and financial condition.

Our heavy crude oil in California may be less economic than lighter crude oil and natural gas. As of December 31, 2009, approximately 48% of our proved reserves, or 112 million barrels, consisted of heavy oil. Light crude oil represented 8% and natural gas represented 44% of our oil and natural gas reserves. Heavy crude oil 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 the EOR process of 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. We had a long-term contract to sell all of our heavy crude oil in California for approximately $8.10 below WTI with Big West of California (BWOC). On December 22, 2008, Flying J, Inc. and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC each filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed us that it was unable to receive our production. On March 17, 2009, we entered into a stipulation with BWOC, terminating the contract effective as of March 16, 2009. We recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of that $38.5 million due from BWOC, $11.8 million represents 20 days of our December 2008 crude oil sales and an administrative claim under the bankruptcy proceedings and $26.7 million represents November 2008 and the balance of December 2008 crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract. While we also have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, the information received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected.

Additionally, 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.

We may be unable to meet our drilling obligations. We have contractual obligations on our Piceance assets in Colorado. We must spud 120 wells by February 2011 to avoid penalties of $0.2 million per well. Our ability to meet this commitment depends on the capital resources available to us to fund our activities to develop these assets on the schedule required to avoid penalties or loss of related leases. There is no assurance that our operating cash flow or alternative sources of capital investment from partnerships, joint ventures or other investment opportunities with third parties will be available to us in sufficient amount to develop these assets on the schedule required to avoid penalties.

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Our financial counterparties may be unable to satisfy their obligations. We rely on financial institutions to fund their obligations under our senior secured credit facility 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 two 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.

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, 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 natural gas and crude oil differentials.

Price differentials may widen in the future. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, 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 based on 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, insufficient pipeline 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 the benchmark price for oil and natural gas and the wellhead price we receive could adversely affect our financial condition.

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 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 five 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 Bbl/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 2,700 Bbl/D in 2009.

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 28% of our steam capacity as of December 31, 2009. These facilities are dependent on reasonable power 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 power 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. Our power contracts have been extended until December 31, 2010, but are subject to earlier termination by the utility counterparty in certain circumstances.

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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. All of our power contracts in place with the utilities are expected to terminate in 2010, and while we intend to enter into future contracts with the utilities, all of the terms of such contracts are currently the subject of contested proceedings before the California Public Utilities Commission (CPUC). 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 new SRAC pricing formula retroactively, if applied so as to require payment on a one-time basis, could have a material adverse effect on our financial condition and results of operations. During the California energy crisis in 2000 and 2001, we had electricity sales contracts with various utilities 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. See “Item 1. Business - Electricity” for more information about our electricity contracts.

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 gas price and interest rate hedging 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 hedging transactions with respect to a portion of our oil and 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. We also utilize interest rate hedges 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 hedging transactions 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. Hedging 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 gas reserves. To maintain production levels, we must locate and develop or acquire new oil and 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 to acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and 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 gas reserves.

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves, future production, oil and 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 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 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 and exploration and prevailing oil and 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.

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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. Declines in oil and natural gas prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, 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 gas properties under the successful efforts accounting method. If net capitalized costs of our oil and 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 gas properties is computed on a field-by-field basis. Once incurred, a write-down of oil and gas properties is not reversible at a later date even if oil or gas prices increase. It is possible that declining 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 facility.

Approximately 47% of our total estimated proved reserves at December 31, 2009 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 and results of operations. 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 gas companies actively bid for desirable oil and 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 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 and results of operations.

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 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;
- 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. For example, although we expect that our diatomite production will average approximately 5,000 BOE/D by the end of 2010, actual production from these assets could be significantly lower.

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

- fires;
- explosions;
- blow-outs;
- uncontrollable flows of oil, 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;
- 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 and results of operations. 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 complex 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. All facets of our operations are regulated extensively at the federal, state, regional and local levels. Environmental laws and regulations impose limitations on our discharge of pollutants into the environment, establish standards for our management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose on us obligations to investigate and remediate contamination in certain circumstances. We also must satisfy, in some cases, federal and state requirements for providing environmental assessments, environmental impact studies and/or plans of development before we commence exploration and production activities. Environmental and other requirements applicable to our operations generally have become more stringent in recent years, and compliance with those requirements more expensive. Frequently changing environmental and other governmental 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 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 penalties.

From time to time we have experienced accidental spills, leaks and other discharges of contaminants at some of our properties. We could be liable for the investigation or remediation of such contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage. We have incurred expenses and penalties in connection with remediation of contamination 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 even where the contamination does not result from 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 to attempt to stop such projects, including decisions by the Bureau of Land Management regarding several leases in Utah that we have been awarded.

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Climate change legislation or regulatory initiatives may adversely affect our operations, our cost structure, and the demand for oil and natural gas. There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of greenhouse gasses (GHG). Moreover, in 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for GHGs, became binding on all those countries that had ratified it. International discussions are currently underway to develop a treaty to replace the Kyoto Protocol after its expiration in 2012. While it is not possible at this time to predict how regulation that may be enacted to address GHG emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, and the proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process. The adoption of any future federal or state laws or implementing regulation imposing reporting obligation 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 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 and results of operations.

The adoption of derivative legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business. Congress is currently considering legislation to impose restrictions on certain derivatives, including in some cases energy derivatives, which could affect the use of derivatives in hedging transactions. For example, the “cap and trade” legislation contains provisions that, until other derivative regulation is enacted, would subject almost all energy commodity derivative transactions, including hedging, to the authority of the Commodity Futures Trading Commission, which can impose capital, margin and position limits on traders and require on-exchange trading and other forms of regulation. Separately, the House of Representatives adopted financial regulatory reform legislation on December 11, 2009, that, among other things, would impose comprehensive regulation on the over-the-counter derivatives marketplace. Although it is not possible at this time to predict whether or when Congress may act on derivatives regulation legislation, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge certain risks associated with our business or on the cost of our hedging activity.

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.

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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 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 and environmental 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 acquiring producing properties, 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 results of operations and financial condition 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 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.

In 2008, we executed two transportation precedent agreements with Ruby Pipeline LLC (Ruby), which was proposing to construct a pipeline with a capacity of 1,500,000 decatherms per day from the Opal Hub in southwest Wyoming to the Malin Hub at the California-Oregon border. One of the precedent agreements is for 25,000 decatherms per day commencing upon operation of the pipeline and the other is for 12,857 decatherms commencing two years after the commencement of operation of the pipeline for an average of 35,000 decatherms per day over the 10 year term. One of the conditions, among many, under these agreements, is that we will maintain evidence of satisfaction of creditworthiness. Under the agreements, we as the shipper have the option to choose among a variety of creditworthiness supports, one of which is that the two parties have to reach a mutually agreeable creditworthiness support. Ruby's initial proposal is not acceptable to us and on January 29, 2010, we proposed an alternative credit arrangement that would be satisfactory to us and would be consistent with that offered by Ruby to other shippers who we believe are less creditworthy than us. On February 9, 2010, Ruby responded by rejecting Berry's proposal and filing a lawsuit against us. This dispute may result in a termination of our contracts for capacity on this pipeline in which case we will make alternative arrangements for the transportation and marketing of our production. Additionally, the termination of these contracts may also result in monetary damages.

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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 Federal Energy Regulatory Commission (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, that 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 the results of our operations and financial condition. 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 title problems, the amount paid for affected oil and natural gas leases or estates can be generally lost, and a prospect can become undrillable.

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We have received a notice of proposed civil penalty of $69.6 million from the Bureau of Land Management that may result in our payment of a significant penalty. In July 2009, we received a notice of proposed civil penalty from the Bureau of Land Management (the BLM) related to our alleged non-compliance during 2007 with regulations relating to the operation and position of certain valves in our Uinta basin operations. The regulations are intended to address production security on Federal and tribal lands managed by the BLM. The proposed civil penalty is $69.6 million and reflects the theoretical maximum penalty amount under applicable regulations, absent mitigating factors. We immediately remediated the instances of non-compliance in 2007, cooperated fully with the BLM's investigation and we believe no production was lost, all royalties were paid and there was no harm to the environment. Due to the above mitigating factors, among others, we believe this matter will be resolved by the payment of a penalty that will not exceed $2.1 million and have accrued such amount in the second quarter of 2009. However, there can be no assurance that any penalty would not be in excess of $2.1 million or have a material adverse affect on us.

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 liquidity.

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

No matters were submitted to a vote of security holders during the most recently ended fiscal quarter.

Executive Officers. Listed below are the names, ages (as of December 31, 2009) and positions of our executive officers and their business experience during at least the past five years. All our officers are reappointed in May of each year at an organizational meeting of the Board of Directors. There are no family relationships between any of the executive officers and members of the Board of Directors.

ROBERT F. HEINEMANN, 56, 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 2003. 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, 39, 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 participated in numerous equity, debt and M&A transactions in the energy industry.

MICHAEL DUGINSKI, 43, 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, 49, 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.

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DAN ANDERSON, 47, 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, 66, 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 us. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000.

SHAWN M. CANADAY, 34, has held the position of Vice President of Finance and Treasurer since August 2009 and 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, 46, has held the position of Vice President, Corporate Development since January 2010, 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.

KENNETH A. OLSON, 54, has been Corporate Secretary since December 1985 and was Treasurer from August 1988 until December 2004.

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

Our Class A Common Stock is listed on the New York Stock Exchange (NYSE) under the symbol BRY. The Class B Stock is not publicly traded. The market data and dividends for 2009 and 2008 are shown below:

	2009			2008		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 13.10	$ 5.50	$ .075	$ 47.20	$ 33.41	$ .075
Second Quarter	22.76	10.52	.075	62.15	45.73	.075
Third Quarter	28.46	14.90	.075	61.72	30.99	.075
Fourth Quarter	31.37	24.87	.075	37.76	6.02	.075
Total Dividends Paid			$ .300			$ .300

The number of holders of record of our Class A Common Stock was 544 as of February 1, 2010. There was one Class B Shareholder of record as of February 1, 2010.

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, 2009, we have paid dividends on our Common Stock for 81 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 1) senior secured revolving credit facility to the greater of $20 million or 75% of net income, and 2) bond indentures of up to $20 million annually irrespective of our coverage ratio or net income 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	3,653,340	$ 25.36	218,635
Equity compensation plans not approved by security holders	none	none	none

Issuer Purchases of Equity Securities.

None.

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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, 2004 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index (S&P 500) 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 15 companies which make up the Peer Group are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Encore Acquisition Co., Forest Oil Corp., Petrohawk Energy Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Range Resources Corp., St. Mary Land & Exploration Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp.

	12/04	12/05	12/06	12/07	12/08	12/09
Berry Petroleum Company	100.00	121.11	132.63	191.74	33.06	130.22
S&P 500	100.00	104.91	121.48	128.16	80.74	102.11
Russell 2000	100.00	104.55	123.76	121.82	80.66	102.58
Peer Group	100.00	148.61	150.33	218.15	116.04	179.66

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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 and have been revised from the presentation, except for the reserve data, to reflect (1) the presentation as discontinued operations of our DJ Basin assets, which were sold on April 1, 2009 and (2) our implementation of authoritative guidance related to whether instruments granted in share based payment transactions are participating securities, which requires the revision of prior period basic and diluted earnings per share data. The statements of income data for the years ended December 31, 2009, 2008 and 2007 and balance sheet data as of December 31, 2009 and 2008 included in this table were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data).

	2009	2008	2007	2006	2005
Financial Information					
Sales of oil and gas	$506,691	$649,248	$433,208	$396,497	$324,473
Sales of electricity	36,065	63,525	55,619	52,932	55,230
Gas marketing sales	22,806	35,750	-	-	-
Gain (loss) on sale of assets (1)	826	(1,297)	54,173	103	130
Operating costs - oil and gas production	156,612	188,758	130,940	111,490	93,423
Operating costs - electricity generation	31,400	54,891	45,980	48,281	55,086
Gas marketing expense	21,231	32,072	-	-	-
Production taxes	18,144	26,876	14,651	12,169	10,462
General and administrative expenses (G&A)	49,237	54,279	39,663	36,474	21,270
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	139,919	125,595	82,861	61,419	34,320
Electricity generation	3,681	2,812	3,568	3,343	3,260
Income from continuing operations	59,968	121,776	127,284	97,857	103,684
(Loss) income from discontinued operations, net of taxes	(5,938)	11,753	2,644	10,086	8,672
Net income	54,030	133,529	129,928	107,943	112,356
Basic net income from continuing operations per share	1.31	2.70	2.85	2.21	2.34
Basic net (loss) income from discontinued operations per share	(0.13)	0.26	0.06	0.23	0.20
Basic net income per share	1.18	2.96	2.91	2.44	2.54