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,” “a 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 UndevelopedReserves	
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

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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