BERRY PETROLEUM CO
Form 10-K
March 06, 2006

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, 2005**
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)

5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: **(661) 616-3900**

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, $.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 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. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act. (Check one): Large accelerated filerx Accelerated filero Non-accelerated filero

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, 2005, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $962,312,197. As of February 10, 2006, the registrant had 21,077,915 shares of Class A Common Stock outstanding. The registrant also had 898,892 shares of Class B Stock outstanding on February 10, 2006 all of which is 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

Item 1. Business

General. Berry Petroleum Company, (Berry or Company), is an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. While the Company was incorporated in Delaware in 1985 and has been a publicly traded company since 1987, it can trace its roots in California oil production back to 1909. Currently, Berry's principal reserves and producing properties are located in California, Utah and Colorado. The Company has its corporate headquarters in Bakersfield, California and a regional office in Denver, Colorado. The Company is increasing office space in both locations to accommodate growth. Information contained in this report on Form 10-K reflects the business of the Company during the year ended December 31, 2005 unless noted otherwise.

The Company's website is located at http://www.bry.com. The website can be used to access recent news releases and Securities and Exchange Commission (SEC) filings, crude oil price postings, the Company's Annual Report, Proxy Statement, Board committee charters, code of business conduct and ethics, the code of ethics for senior financial officers, and other items of interest. SEC filings, including supplemental schedules and exhibits, can also be accessed free of charge through the SEC website at http://www.sec.gov.

Corporate Strategy. Berry Petroleum Company's mission is to increase shareholder value, primarily through increasing the net asset value, and maximizing the cash flow and earnings of the Company's assets. The strategies to accomplish these goals include:

- ***Growing production and reserves from existing assets while managing expenses*** - The Company intends to increase production and reserves annually and increase both net income and cash flow in total and per share. The Company will continue to focus on the further development of its properties through developmental drilling, down-spacing, well completions, remedial work and by application of enhanced oil recovery (EOR) methods, and optimization technologies, as applicable. With respect to the California heavy oil reserves, the Company owns three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the economic production of heavy oil.
- ***Acquiring more light oil and natural gas assets with significant growth potential in the Rocky Mountain and Mid-Continent region -*** The Company will compete to acquire oil and gas properties with proved reserves, probable reserves and/or sizeable acreage positions that the Company believes contain substantial reserves which can be developed at reasonable costs. As part of its resource diversification strategy, Berry desires to add natural gas production and reserves to complement its significant crude oil resource base. The Company has identified the Rocky Mountain and Mid-Continent region as its primary areas of interest for diversification.
- ***Appraising the Company's exploitation and exploration projects in an expedient manner -*** The Company has been successful in adding significant acreage positions in the last two years with the intent of drilling exploration wells to test the potential of the acreage for the economic production of hydrocarbons. Its goal is to appraise this potential as quickly as is prudently possible.
- ***Investing the Company's capital in an efficient, disciplined manner -*** Investing the Company's capital prudently is of paramount importance in achieving long-term success. The oil and gas business is very capital intensive so managing the business with a focus on utilizing the available capital on projects where it is likely to have success in increasing production and/or reserves at attractive returns to shareholders. A portion of the Company's capital will be directed to higher risk projects that have the potential for higher reward.
- ***Utilizing joint ventures with respected partners to enter new basins -*** The Company believes that it is beneficial to utilize the skills and knowledge of other industry participants upon entering new basins or areas of operations as it

can reduce the risk and improve the success in the area.

Berry has the industry talent, experience, organization and motivation to accomplish the above strategies to fulfill its mission of increasing shareholder value. Berry also has the financial capacity and skill sets to accomplish these strategies. In addition to internally generated funds, it has a $500 million unsecured credit facility with a current borrowing base of $350 million which may be utilized in adding prospective acreage, reserves and/or production through acquisitions.

Proved Reserves and Revenues. As of December 31, 2005, the Company's estimated proved reserves were 126 million barrels of oil equivalent, (BOE), of which 74% are heavy crude oil, 8% light crude oil and 18% natural gas. Nearly 40% of reserves are owned in fee. Geographically, 74% of the Company’s reserves are located in California and 26% in the Rocky Mountain and Mid-Continent region. Proved undeveloped reserves make up 28% of the Company's proved total. The projected capital to develop these proved undeveloped reserves is $201million, at an estimated cost of approximately $5.54 per BOE. Approximately 77% of the capital to develop these reserves is expected to be expended in the next five years. Production in 2005 was 8.4 million BOE, up 12% from production of 7.5 million BOE in 2004. The Company’s reserves-to-production ratio was unchanged at 14.6 years at year-end 2005, compared to year-end 2004.

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The following table depicts all of the Company's producing assets as of December 31, 2005. Berry operates all of the assets, except Wyoming:

State	Name	Type	Daily Production (BOE/D)	% of Daily Production	Proved Reserves (BOE) in thousands	% of Proved Reserves	Oil & Gas Revenues before hedging (in millions)	% of Oil & Gas Revenues
CA	Midway-Sunset	Heavy oil	12,214	*53%*	68,071	*54%*	$ 199	*50%*
UT	Brundage Canyon	Light oil/Natural gas	5,079	*22*	15,116	*12*	98	*25*
CA	Placerita	Heavy oil	2,654	*12*	16,592	*13*	48	*12*
CO	Tri-State	Natural gas	1,600	*7*	17,442	*14*	26	*7*
CA	Montalvo	Heavy oil	728	*3*	6,869	*5*	12	*3*
CA	Poso Creek	Heavy oil	544	*2*	2,046	*2*	10	*3*
WY/CA	Various	Various	196	*1*	149	-	2	-
Totals			**23,015**	***100%***	**126,285**	***100%***	**$ 395**	***100%***

The Company continued to engage DeGolyer and MacNaughton (D&M) to appraise the extent and value of its proved oil and gas reserves and the future net revenues to be derived from properties of the Company for the year ended December 31, 2005. D&M is an independent oil and gas consulting firm located in Dallas, Texas. In preparing their reports, D&M reviewed and examined geologic, economic, engineering and other data considered applicable to properly determine the reserves of the Company. They also examined the reasonableness of certain economic assumptions regarding forecasted operating and development costs and recovery rates in light of the economic environment on December 31, 2005. See Supplemental Information About Oil & Gas Producing Activities (Unaudited) for the Company's oil and gas reserve disclosures.

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

Operations. In California, Berry operates all of its principal oil and gas producing properties. The Midway-Sunset, Placerita and Poso Creek fields contain predominantly heavy crude oil which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity which allows the oil to flow to the wellbore for production. Berry utilizes cyclic steam and/or steam flood recovery methods in all of these fields in addition to primary recovery methods at its Montalvo field. Berry is able to produce its heavy oil at its Montalvo field without steam since the majority of the producing reservoir is at a depth in excess of 11,000 feet and the reservoir temperature is high enough to produce the oil without the assistance of additional heat from steam. 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 Mountain and Mid-Continent region, crude oil produced from the Brundage Canyon field is transported by truck, while its gas production, net of field usage, is transported by gathering or distribution systems to the Questar Pipeline. Natural gas produced from the eastern Colorado Niobrara gas assets is transported by Company and third party gathering lines to one of two main pipelines. The Company has a pipeline gathering system and gas compression facilities for delivery into these two interstate gas lines in this region.

Crude Oil and Natural Gas Marketing

Economy. The global and California crude oil markets continue to remain strong. Product prices continued to exhibit an overall-strengthening trend through 2005. The range of West Texas Intermediate (WTI) crude prices for 2005, based upon NYMEX settlements, was a low of $42.12 and a high of $69.81. The Company expects that crude prices will continue to be volatile in 2006.

	2005	2004	2003
Average NYMEX settlement price for WTI	$ 56.70	$ 41.47	$ 30.99
Average posted price for Berry's:			
Utah light crude oil	53.03	38.60	27.63
California 13 degree API heavy crude oil	44.36	32.84	25.33
Average crude price differential between WTI and Berry's:			
Utah light crude oil	3.67	2.87	3.36
California 13 degree API heavy crude oil	12.34	8.63	5.66

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The above posting prices and differentials are not necessarily amounts paid or received by the Company due to the contracts discussed below. While the crude oil price differential between WTI and California's heavy crude was fairly consistent with historical averages in 2003 at just under $6.00 per barrel, the differential widened dramatically during 2004 and 2005. On December 31, 2005 the differential was $11.61 and ranged from a low of $10.27 to a high of $14.83 per barrel during the year. Crude oil price differentials between WTI and Utah's light crude oil were fairly consistent during 2003, 2004 and 2005 and were between $3 and $5 per barrel. On December 31, 2005 the differential was $4.67 and ranged from a low of $3.73 to a high of $4.77 per barrel during the year.

Oil Contracts. Berry markets its crude oil production to competing buyers including independent and major oil refining companies. Because of the Company's ability to deliver significant volumes of crude oil over a multi-year period, the Company secured a three-year sales agreement, beginning in late 2002, with a major oil company whereby the Company sold over 90% of its California production under a negotiated pricing mechanism. This contract ended on January 31, 2006. Pricing in this agreement was based upon the higher of the average of the local field posted prices plus a fixed premium, or WTI minus a fixed differential near $6.00 per barrel. This contract allowed the Company to improve its California revenues over the posted price by approximately $41 million and $13 million in 2005 and 2004, respectively.

On November 21, 2005, the Company entered into a new crude oil sales contract for its California production for deliveries beginning February 1, 2006 and ending January 31, 2010. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of 1) the WTI NYMEX crude oil price less a fixed differential approximating $8.15, or 2) heavy oil field postings plus a premium of approximately $1.35. The initial term of the contract is for four years with a one-year renewal at the Company's option. The agreement effectively eliminates the Company's exposure to the risk of a widening WTI to California heavy crude price differential over the next four years and allows the Company to effectively hedge its production based on WTI pricing similar to the previous contract. If this contract had been in place during 2005, it would have allowed the Company to improve its California revenues over the posted prices by approximately $25 million in 2005, but $16 million below what was actually received by the Company under the contract in place in 2005.

Brundage Canyon crude oil production, which is approximately 40 degree API gravity, is sold under contract at WTI less a fixed differential approximating $2.00 per barrel. This contract expires on September 30, 2006. Any new contract will be negotiated based on market prices. The Company believes the differential has widened by several dollars per barrel. The majority of this crude oil, while light, is a "paraffinic" crude, and can be processed efficiently by only a limited number of stranded inland refineries. The production of this type crude is increasing regionally and beginning to strain the capacity of these refineries. Other new crude sources from the region are pressuring pricing. If these refineries limit the volumes of this parraffinic crude oil they are willing to process, it could impact the marketability of this type of crude which, for Berry, represents approximately 3,500 Bbl/D of production or approximately 15% of total current production. The Company is investigating its market opportunities for this crude oil. If market prices continue to deteriorate, the Company may allocate its capital expenditures to projects which produce natural gas and crude oils with lower paraffinic content until the refinery constraint is resolved.

Natural Gas Marketing. Berry markets produced natural gas from Colorado, Utah, Wyoming and California. Generally, natural gas is sold at monthly index related prices plus an adjustment for transportation. Certain volumes are sold at a daily spot related price.

	2005	2004	2003
Annual average closing price per MMBtu for:			

NYMEX Henry Hub (HH) prompt month natural gas contract	$ 9.01	$ 6.18	$ 5.84
Rocky Mountain Questar first-of-month indices (Brundage Canyon sales)	6.73	5.05	4.00
Rocky Mountain CIG first-of-month indices (Tri-State sales)	6.95	5.17	4.04
Average natural gas price per MMBtu differential between NYMEX HH and:			
Questar	2.28	1.13	1.84
CIG	2.06	1.01	1.80

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The Company has physical access to interstate gas pipelines to move gas to or from market. To assure delivery of gas, the Company has entered into several long-term gas transportation contracts as follows:

Firm Transportation Summary

Name	From	To	Quantity (Avg. MMBtu/D)	Term	2005 base costs per MMBtu	Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$ .6425	$ 20,640
Questar Pipeline	Brundage Canyon	Salt Lake City, UT	2,500	9/2003 to 4/2007	.1739	211
Questar Pipeline	Brundage Canyon	Salt Lake City, UT	2,800	9/2003 to 9/2007	.1739	317
KMIGT	Yuma County, CO	Grant, KS	2,500	1/2005 to 10/2013	.2270	1,624
Cheyenne Plains Gas Pipeline	Tri-State, CO	Panhandle Eastern Pipeline	11,000	(Est.) Q4 2006 to Q4 2016	.3400	13,662
Total			**30,800**			**$ 36,454**

Royalties. See Item 7A Quantitative and Qualitative Disclosures about Market Risk.

Hedging. See Item 7A Quantitative and Qualitative Disclosures about Market Risk and Note 15 to the financial statements.

Concentration of Credit Risk. See Note 4 to the financial statements.

Steaming Operations

Cogeneration Steam Supply. As of December 31, 2005, approximately 74% of the Company's proved reserves, or 93 million barrels, consisted of heavy crude oil produced from depths of less than 2,000 feet. The Company, in pursuing its goal of being a cost-efficient heavy oil producer in California, has remained focused on minimizing its steam cost. One of the main methods of keeping steam costs low is through the ownership and efficient operation of cogeneration facilities. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility are located in the Company’s Midway-Sunset field. The Company also owns a 42 MW cogeneration facility which is located in the Placerita field. Steam generation from these cogeneration facilities is more efficient than conventional steam generation as both steam and electricity are concurrently produced from a common fuel stream. By maintaining a correlation between electricity and natural gas prices, the Company is able to better control its cost of producing steam.

Conventional Steam Generation. In addition to these cogeneration plants, the Company owns 16 conventional boilers. The quantity of boilers operated at any point in time is dependent on 1) the steam volume required for the Company to achieve its targeted production and 2) the price of natural gas compared to the price of crude oil sold.

Total barrels of steam per day (BSPD) capacity as of December 31, 2005 is as follows:

Total steam generation capacity of Cogeneration plants	38,000
Additional steam purchased under contract with third party	2,000
Total steam generation capacity of conventional boilers	43,000
Total steam capacity	83,000

The average volume of steam injected for the years ended December 31, 2005 and 2004 was 70,032 and 69,200 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 control over the aggregated cost of steam generation. The Company's steam supply and flexibility are crucial for the maximization of California thermally enhanced heavy oil production, cost control and ultimate reserve recovery.

The Company believes that it may become necessary to add additional steam capacity for its future development projects at Midway-Sunset and Poso Creek to allow for full development of its properties. The Company regularly reviews its most economical source for obtaining additional steam to achieve its growth objectives.

Most of the Company's conventional steam generators operated in 2005 to achieve the Company's goal of increasing heavy oil production to record levels. Approximately 70% of the volume of natural gas purchased to generate steam and electricity is based upon SoCal Border indices. While there are no transportation charges for gas purchased at the SoCal Border location, all locations except the central portion of the Midway-Sunset field pay distribution/transportation charges to either SoCal Gas or Pacific Gas &

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Electric (PG&E) to have the gas delivered to the field. The remaining 30% of supply volume is purchased in Wyoming and moved to the Midway-Sunset field using the Company's firm transport on the Kern River Pipeline. This gas is purchased based upon the Rocky Mountain Northwest Pipeline (NWPL) index.

	2005	2004	2003
Average SoCal Border Monthly Index Price per MMBtu	$ 7.37	$ 5.60	$ 5.00
Average Rocky Mountain NWPL Monthly Index Price per MMBtu (*contract began May 2003)	6.96	5.24	4.34*

The Company historically was a net purchaser of natural gas and thus its net income was negatively impacted when natural gas prices rose higher than its oil equivalent. In 2005, due to its eastern Colorado Niobrara gas acquisition, the Company on a gas balance basis achieved parity. Thus, going forward, the Company is a net seller of gas and operationally should benefit when gas prices are higher. The balance between natural gas (MMBtu/D) consumed and produced during the month of December 2005 was approximately as follows:

Natural gas consumed in:	
Cogeneration operations	27,000
Conventional boilers	11,000
Total natural gas consumed	38,000
Less: Company's estimate of approximate natural gas consumed to produce electricity (1)	(20,000)
Total approximate natural gas volumes consumed to produce steam	18,000
Natural gas produced:	
Tri-State (Niobrara)	11,900
Brundage Canyon (associated gas)	11,400
Other	1,700
Total natural gas volumes produced in operations	25,000

(1) The Company estimates this volume based on electricity revenues divided by the purchase price, including transportation, per MMBtu for the respective period.

Electricity.

Generation. The total annual average electrical generation of the Company's three cogeneration facilities is approximately 93 megawatts (MW), of which the Company consumes approximately 8 MW for use in its operations. Each facility is centrally located on an oil producing property such that the steam generated by the facility is capable of being delivered to the wells that require steam for the enhanced oil recovery process. The Company's investment in its cogeneration facilities has been for the express purpose of lowering the steam costs in its 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 the Company's cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of the Company's power contracts. The Company views any profit or loss from the generation of electricity as a decrease or increase,

respectively, to its total cost of producing its heavy oil in California. DD&A related to the Company's cogeneration facilities is allocated between electricity operations and oil and gas operations using a similar allocation method.

Sales Contracts. Historically, the Company has sold electricity produced by its cogeneration facilities to two California public utilities, Southern California Edison Company (Edison) and PG&E, under long-term contracts. These contracts are referred to as Standard Offer (SO) contracts under which the Company is paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. An SO2 contract is more beneficial as it receives a higher capacity payment than an SO1 contract. The SRAC energy price is currently determined by a formula that reflects the utility's marginal fuel cost and a conversion efficiency that represents a hypothetical resource to generate electricity in the absence of the cogenerator. During most periods natural gas is the marginal fuel for California utilities so this formula provides a hedge against the Company's cost of gas to produce electricity and steam in its cogeneration facilities. A proceeding is now underway at the California Public Utilities Commission (CPUC) to review and revise the methodology used to determine SRAC energy prices. This proceeding is currently scheduled to be completed by the third quarter of 2006. There is no assurance that any new methodology will continue to provide a hedge against the Company's fuel cost or that a revised pricing mechanism will be as beneficial as the current contract pricing.

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The original SO contract for Placerita Unit 1 continues in effect through March 2009, which makes up approximately 17% of total approximate barrels of steam per day. The modified SRAC pricing terms of this contract reflect a fixed energy price of 5.37 cents/kilowatt hour (KWh) through June 2006, at which time the energy price reverts to the SRAC pricing methodology. The Company will be paid a reduced capacity payment that is fixed through the term of the contract.

In December 2004, the Company executed a five-year SO contract with Edison for the Placerita Unit 2 facility, and five-year SO contracts with PG&E for the Cogen 18 and Cogen 38 facilities, each effective January 1, 2005. Pursuant to these contracts, the Company is paid the purchasing utility's SRAC energy price and a capacity payment that is subject to adjustment from time to time by the CPUC. 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 SO contracts, and similar one-year SO 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 retroactively adjust the prices to the extent it was later determined that such prices did not comply with the requirements of the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA).

The Company believes that Qualifying Facilities (QF), such as the Company's facilities, provide an important source of distributive power generation into California's electricity grid, and as such, that the Company's facilities will be economic to operate for at least the current five-year contract term. Based on the current pricing mechanism for its electricity under the contracts (which includes electricity purchased for internal use), the Company expects that its electricity revenues will be in the $50 million to $60 million range for 2006.

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	Jun-06 (1)	20	-	6,600
Placerita Unit 2	SO1	Edison	Dec-09	16	4	6,700
Midway-Sunset						
Cogen 18	SO1	PG&E	Dec-09	12	4	6,600
Cogen 38	SO1	PG&E	Dec-09	37	-	18,000

(1) After expiration at June 2006, the contract will convert to SO1 through its expiration at March 2009.

Competition. The oil and gas industry is highly competitive. As an independent producer, the Company does not own any refining or retail outlets and, therefore, it has little control over the price it receives for its crude oil. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to the Company's customers. In acquisition activities, significant competition exists 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 the Company, Management believes that Berry is in a position to compete effectively due to its efficient operating cost structure, transaction flexibility, strong financial position, experience and determination.

Employees. On December 31, 2005, the Company had 209 full-time employees, up from 156 full-time employees on December 31, 2004.

Berry's Net Oil and Gas Producing Properties at December 31, 2005.

Name	% Average Working Interest	Total Net Acres	Proved Reserves (BOE) in thousands	Proved Developed Reserves (BOE) in thousands	% of Total Proved Reserves	Proved Undeveloped Reserves (BOE) in thousands	% of Total Proved Reserves	Average Depth of Producing Reservoir (feet)
Midway-Sunset, CA	99	4,836	68,071	60,627	*48%*	7,443	*6%*	1,200
Brundage Canyon, UT	100	45,420	15,116	8,554	*7*	6,561	*5*	6,000
Placerita, CA	100	965	16,592	7,462	*6*	9,130	*7*	1,800
Tri-State, CO/KS/NE	50	315,473	17,442	8,411	*7*	9,031	*7*	2,600
Montalvo, CA	100	8,563	6,869	2,811	*2*	4,059	*3*	11,500
Poso Creek, CA	100	680	2,046	2,046	*2*	-	-	1,200
Various	15	815	149	150	-	-	-	various
Totals		**376,752**	**126,285**	**90,061**	***72%***	**36,224**	***28%***	

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San Joaquin Valley Basin

Midway-Sunset, California - Berry owns and operates working interests in 38 properties, including 23 owned in fee, in the Midway-Sunset field. Production from this field relies on thermal enhanced oil recovery (EOR) methods, primarily cyclic steaming.

2005 - Development activities at Midway-Sunset continued to be focused on horizontal drilling to improve ultimate recovery of original oil-in-place, reduce the development and operating costs of properties and to accelerate production.
2006 - Capital of $40 million ($15 million for development and $25 million for exploration/appraisal) is directed to 1) development - maximizing the recovery from horizontal wells, improving steam efficiency and expanding two steam flood projects and 2) exploration/appraisal - expanding of the Diatomite project which includes up to 50 wells and related facilities.

Poso Creek, California - Berry acquired these properties beginning in 2003 and is evaluating the potential for thermal EOR.

2005 - The Company initiated a steam flood on the property.
2006 - Capital of $5 million is directed at drilling infill wells and, upon success, expanding the steam flood area.

Los Angeles Basin

Placerita, California - Berry owns and operates working interests in 13 properties, including 9 leases and 4 fee properties, in the Placerita field. Production relies on thermal recovery methods, primarily steam flooding.

2005 - Began major recompletion effort in mature steam flood and drilled 10 wells on northern acreage.
2006 - Capital of $8 million is directed at converting northern leases to steam flood, expanding another steam flood project and focusing on utilizing optimization technology to improve recovery.

Ventura Basin

Montalvo, California - Berry owns 6 leases in the Ventura Basin comprising the entire Montalvo field. The State of California is the lessor for 2 of these leases. The wells produce heavy oil and due to the depth of the reservoir, steam injection is not necessary.

2005 - Berry performed several well recompletions.
2006 - Capital of $8 million is directed at testing the western Sespe reservoir through additional drilling and adding production in the Colonia zone.

Uinta Basin

Brundage Canyon, Utah - The Brundage Canyon leasehold in Duchesne County, northeastern Utah consists of federal, tribal and private leases.

2005 - The Company continued its focus on development of the Brundage Canyon property, drilling 53 wells including 33 infill wells to validate 40-acre spacing.

2006 - Capital of $58 million is directed at continuing the development of the Green River formation, including testing 20-acre infills.

Lake Canyon Prospect, Utah - The Company holds, with an industry partner, a 169,000 gross acre block which is located immediately west of the Company's Brundage Canyon producing properties. The Company will drill and operate the shallow wells which target light oil and natural gas in the Green River formation and retain up to a 75% working interest. The Company's partner will drill and operate the deep wells which target natural gas in the Mesaverde and Wasatch formations. Berry will hold up to a 25% working interest in these deep wells. The Ute Tribe has the option to participate in each well and obtain a 25% working interest which would reduce the Company's and its partner's participation. The Ute Tribe did participate in the first two shallow Green River wells.

2005 - The Company drilled 2 shallow Green River oil and gas wells and participated in a 57 square mile 3-D seismic survey. In October 2005, the Company's partner began drilling a deep Mesaverde gas test well that reached targeted depth of 14,500 feet in December. This deep well is being evaluated. In January 2006, the Company announced that its 2 shallow wells have commercial quantities of oil and gas.
2006 - Capital of $4 million is directed at an additional 4 shallow wells and participation in deep Mesaverde tests. Upon further success with the shallow wells, the Company will accelerate development and capital on this project.

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Coyote Flats Prospect, Utah - In December 2004, the Company entered into a development agreement with an industry partner to develop their Coyote Flats prospect. The property is located approximately 45 miles southwest of the Company's Brundage Canyon property. The Company is obligated to drill four test wells into the Ferron sand to a depth of approximately 7,500 feet and also drill a five well Emery coalbed methane (CBM) pilot, found at approximately 4,500 feet. Upon the completion of this total nine well drilling program, the Company will earn a 50% working interest in the approximately 69,250 gross (33,500 net) acres. The Company expects to complete this nine well drilling program in 2006.

2005 - The Company has drilled 3 Ferron sand test wells in 2005, one of which was a dry hole. The Company began its CBM development with 1 well drilled.
2006 - Capital of $5 million is directed at fulfilling Berry's obligation wells, which consists of four CBM wells and one Ferron well. A gas pipeline is also planned to tie in gas production for sale in mid-summer.

Big Wash Unit, Utah - The Company, and an industry partner, owns working interest in 3 acreage blocks, the largest being the Big Wash Unit, which is located one mile southeast of Brundage Canyon.

2005 - Participated in one deep Mesaverde test in 2005, and the well (net working interest to Berry of 16%) is an economic producer.
2006 - Capital of $2 million is directed at participating in one exploratory gas well in the deep Mesaverde and one exploratory oil well in the shallow Green River formation.

Denver-Julesburg Basin

Tri-State Area (includes eastern Colorado producing assets) - This area is comprised of the following three acquisitions during 2005 totaling approximately 315,000 net acres, including approximately 100,000 net acres of producing acreage:

- Niobrara gas producing assets in Yuma County in northeastern Colorado in which the Company has approximately 52% working interest.
- Eastern Colorado, western Kansas and southwestern Nebraska in which the Company has approximately 50% working interest. The Company's joint venture (JV) will apply seismic technologies to explore and, if successful, develop the Niobrara formation for gas and Sharon Springs shale gas, which lies at less than 2,000 feet, and apply seismic technologies to evaluate oil potential in the Pennsylvanian formations at depths of 4,000 feet to 4,800 feet.
- Colorado's Phillips and Sedgwick Counties in which the Company has approximately 50% working interest. This Niobrara leasehold position is adjacent to and immediately north of Berry's producing natural gas assets in Yuma County.

2005 - In 2005, the Company drilled approximately 103 gross wells as part of its ongoing development program and the initiation of the 40-acre infill program from the existing 80-acre development. The JV's initial exploratory wells at Prairie Star Sherman County, Kansas are commercial. Additionally, the JV drilled 7 gross wells (4 net) in 2005 at Prairie Star.
2006 - Capital of $25 million ($17 million development and $8 million exploration) is directed at drilling over 160 wells to add production from both proved undeveloped and probable reserves and over 30 exploratory wells, based on various seismic data and interpretation. The Company will also participate in at least five 3-D seismic surveys covering in excess of 250 square miles.

Williston Basin

Bakken Play, North Dakota - In 2005, the Company completed several transactions and Berry now has total working interests of 50% in 186,000 gross acres (46,000 net) located in the Williston Basin in North Dakota. These acquisitions, totaling approximately $9 million, provide the Company an entry into the emerging Bakken oil play in the Williston Basin. The acreage covers several contiguous blocks located primarily on the eastern flank of the Nesson Anticline. Development activity in the Middle Bakken play is generally expanding to the area surrounding the Nesson Anticline.

2005 - The Company participated in one exploratory well which is undergoing evaluation.
2006 - Capital of $4 million is directed at participating in at least four exploratory horizontal wells. Berry does not anticipate being the operator of any of these wells.

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Piceance Basin

Grand Valley, Colorado - On January 27, 2006 the Company announced that it had entered into an agreement with a private seller to acquire a 50% working interest in natural gas assets (6,314 gross acres) in the Piceance Basin of western Colorado for approximately $150 million. Berry internally estimates 26 billion cubic feet (Bcf) of proved reserves. Berry has identified over 600 drilling locations based on 10-acre development. Berry will be targeting gas in the Williams Fork section of the Mesaverde formation. The Company increased its 2006 capital budget by an additional $48 million to $208 million to develop this resource. There are two drilling rigs dedicated to this project and based on the productivity of this acreage and surrounding producing operations, Berry is seeking to add additional drilling rigs to accelerate development. Estimated production, net to Berry's interests as of March 1, 2006 is 1 million cubic feet per day. The transaction closed on February 28, 2006.

2006 - Capital of $48 million is directed at beginning the extensive development of the acreage. The Company intends to drill over 30 wells in 2006 and, depending on rig availability and commodity prices, may increase its capital committed to the project.

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The following is a summary of the Company's capital expenditures incurred during 2005 and 2004 and budgeted capital expenditures for 2006:

CAPITAL EXPENDITURES SUMMARY
(in thousands)

	2006 (Budgeted) (1)	2005	2004
CALIFORNIA			
Midway-Sunset field			
New wells	$ 23,380	$ 17,369	$ 11,376
Remedials/workovers	1,145	1,079	1,415
Facilities - oil & gas	14,493	7,879	4,045
Facilities - cogeneration	543	3,053	1,055
General	540	1,271	2,144
	40,101	30,651	20,035
Other California fields			
New wells	10,647	6,965	426
Remedials/workovers	2,650	5,303	1,589
Facilities - oil & gas	7,202	3,677	3,416
Facilities - cogeneration	400	1,446	555
General	110	46	-
	21,009	17,437	5,986
Total California	61,110	48,088	26,021
ROCKY MOUNTAIN AND MID-CONTINENT			
Uinta Basin			
New wells	64,100	50,354	39,467
Remedials/workovers	1,496	3,415	4,597
Facilities	2,500	1,860	1,979
General	552	4	-
	68,648	55,633	46,043
Piceance Basin			
New wells	47,615	-	-
	47,615	-	-
DJ Basin			
New wells/workovers	14,819	11,257	-
Remedials/workovers	275	693	-
Facilities	5,215	2,569	-
General	4,838	387	-
Land and seismic	-	-	-
	25,147	14,906	-
Williston Basin - New wells	4,400	-	161
Total Rocky Mountain and Mid-Continent	145,810	70,539	46,204

Other Fixed Assets	770	647	-
TOTAL	$ 207,690	$ 119,274	$ 72,225

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(1) Budgeted capital expenditures may be adjusted for numerous reasons including, but not limited to, oil, and natural gas price levels and equipment availability, permitting and regulatory issues. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations.

Production. The following table sets forth certain information regarding production for the years ended December 31, as indicated:

	2005	2004	2003
Net annual production: (1)			
Oil (Mbbl)	7,081	7,044	5,827
Gas (MMcf)	7,919	2,839	1,277
Total equivalent barrels (MBOE) (2)	8,401	7,517	6,040
Average sales price:			
Oil (per Bbl) before hedging	$ 47.04	$ 33.43	$ 24.41
Oil (per Bbl) after hedging	40.83	29.89	22.37
Gas (per Mcf) before hedging	7.88	6.13	4.40
Gas (per Mcf) after hedging	7.73	6.12	4.43
Per BOE before hedging	47.01	33.64	24.48
Per BOE after hedging	41.62	30.32	22.52
Average operating cost - oil and gas production (per BOE)	11.79	10.09	9.57

Mbbl - Thousands of barrels
MMcf - Million cubic feet
BOE - Barrels of oil equivalent
MBOE - Thousand barrels of oil equivalent
(1) Net production represents that owned by Berry and produced to its 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, 2005, the Company's properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	8,007	8,007	7,038	7,038	15,045	15,045
Colorado	79,910	67,302	162,966	77,029	242,876	144,331
Illinois	-	-	35,481	33,249	35,481	33,249
Kansas	-	-	424,885	275,494	424,885	275,494
Nebraska	-	-	124,025	57,756	124,025	57,756
North Dakota	-	-	185,976	46,252	185,976	46,252
Utah (1) (2)	9,520	9,360	99,033	66,686	108,553	76,046
Wyoming	3,800	750	3,146	1,130	6,946	1,880
Other	80	19	-	-	80	19
	101,317	85,438	1,042,550	564,634	1,143,867	650,072

(1) Includes 44,583 gross undeveloped acres (22,292 net) where the Company has an interest in 75% of the deep rights and 25% of the shallow rights.
(2) Does not include 125,000 gross (70,000 net) acres, 125,000 gross (23,000 net) acres and 69,000 gross (34,000 net) acres at Lake Canyon (shallow), Lake Canyon (deep) and Coyote Flats, respectively, which the Company can earn upon fulfilling specific drilling obligations.

Gross acres represent acres in which Berry has a working interest; net acres represent Berry's aggregate working interests in the gross acres.

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As of December 31, 2005, the Company has 2,035 gross oil wells (1,951 net) and 976 gross gas wells (419 net). Gross wells represent the total number of wells in which Berry has a working interest. Net wells represent the number of gross wells multiplied by the percentages of the working interests owned by Berry. One or more completions in the same bore hole are counted as one well. Any well in which one of the multiple completions is an oil completion is classified as an oil well.

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

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled (2):						
Productive	13	6	5	5	-	-
Dry (1)	1	1	-	-	-	-
Development wells drilled:						
Productive	213	176	123	111	121	119
Dry (1)	7	5	-	-	1	1
Total wells drilled:						
Productive	226	182	128	116	121	119
Dry (1)	8	6	-	-	1	1

(1) A dry well is a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
(2) Does not include one gross well drilled by the Company's industry partner that is being evaluated at December 31, 2005.

	2005	
	Gross	Net
Total productive wells drilled:		
Oil	113	111
Gas	113	71

Dry hole, abandonment and impairment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations.

California Drilling Rig. The Company entered into a three-year drilling contract for the services of an automated drilling rig. This rig provides a means for Berry to meet at least half of its California new well drilling needs for the next three years, with the other half being met by conventional drilling rigs. The three-year drilling contract begins upon commissioning of the rig which is expected in the second quarter of 2006.

Rocky Mountain and Mid-Continent Region Drilling Rigs. During 2005, the Company purchased two drilling rigs. The first rig is leased to a drilling company under a three year contract, while the second rig is currently being refurbished in preparation for leasing under a similar drilling contract. Owning these rigs allows the Company to successfully meet a portion of its drilling needs in the Uinta Basin over the next several years, while both rigs carry purchase options available to the drilling company.

Other. At year-end, the Company had no subsidiaries, no special purpose entities and no off-balance sheet debt. The Company did not enter into any significant related party transactions in 2005. See Note 17 to the financial statements for discussion regarding Canyon Drilling, LLC.

Environmental and Other Regulations. Berry Petroleum Company is committed to responsible management of the environment, health and safety, as these areas relate to the Company's operations. The Company strives to achieve the long-term goal of sustainable development within the framework of sound environmental, health and safety practices and standards. Berry makes environmental, health and safety protection an integral part of all business activities, from the acquisition and management of its resources through the decommissioning and reclamation of its wells and facilities.

All facets of the Company's operations are affected by a myriad of federal, state, regional and local laws, rules and regulations. Berry is further affected by changes in such laws and by constantly changing administrative regulations. Furthermore, government agencies may impose substantial liabilities if the Company fails to comply with such regulations or for any contamination resulting from the Company's operations. Therefore, Berry has 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 its operations. The costs incurred to ensure

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compliance with environmental, health and safety laws and other regulations are normal operating expenses and are not material to the Company's operating cost. 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. Berry maintains insurance coverage that it believes is customary in the industry although it is not fully insured against all environmental or other risks.

Regulation of Oil and Gas. The oil and gas industry, including the Company's operations, is extensively regulated by numerous federal, state and local authorities, and with respect to tribal lands, and one Native American tribe.

These types of regulation include requiring permits for the drilling of wells, drilling bonds and 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 notice to surface owners and other third parties. Certain laws and regulations may limit the amount of oil and natural gas the Company can produce from its wells or limit the number of wells or the locations at which it can drill. The Company is also subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases and other exploration agreements, fees, taxes, and 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 Regulation Commission (FERC) provided incentives for the development of cogeneration facilities such as those owned by the Company. A domestic electricity generating project must be a QF under FERC regulations in order to take advantage of 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 the FERC determines that a competitive electricity market is available to QFs in its service territory. This amendment does not affect any of the Company's current SO contracts. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utilities' avoided costs. In California, the utility's avoided cost is generally referred to as Short Run Avoided Cost or SRAC.

In order to be a QF, a cogeneration facility must produce not only electricity, but also useful thermal energy for use in an industrial or commercial process for heating or cooling applications in certain proportions to the facility's total energy output, and must meet certain energy efficiency standards. Each of the Company's cogeneration facilities is a QF, pursuant to PURPA.

State Energy Regulation. The CPUC has broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in this state 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 the Company, 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 the

Company is not subject to regulation by the CPUC, the CPUC's implementation of PURPA is important to the Company.

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 such as “will,” “might,” “intend,” “continue,” “target(s),” “expect,” “achieve,” “strategy,” “future,” “may,” “could,” “goal(s),” or other comparable wor or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management’s current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 16 of this Form 10-K filed with the Securities and Exchange Commission, under the heading “Other Factors Affecting the Company's Business and Financial Results" in the section titled "Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

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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. Our revenues, profitability and future growth and reserve calculations depend substantially on reasonable prices for oil and gas. These prices also affect the amount of our cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our credit facility is subject to periodic asset redeterminations based in part on changing expectations of future crude oil and natural gas prices. Lower prices may also reduce the amount of oil and gas that we can produce economically.

Among the factors that can cause fluctuations are:

- domestic and foreign supply of oil and natural gas;
- price and availability of alternative fuels;
- weather conditions;
- level of consumer demand;
- price of foreign imports;
- world-wide economic conditions;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations.

The Company has crude oil hedges on 10,000 Bbl/D for 4 years beginning in 2006. We have an oil collar in place based on WTI pricing with a $47.50 floor and a $70 ceiling.

Our heavy crude in California is less economic than lighter crude oil and natural gas. As of December 31, 2005, approximately 74% of our proved reserves or 93 million barrels, consisted of heavy oil, light crude oil represented 8% and natural gas represented 18% of our oil and gas reserves. Our objective is to diversify our predominantly heavy crude oil base with light crude oil and natural gas.

In November 2005, the Company entered into a new crude oil sales contract for its California production for deliveries beginning February 1, 2006 and ending January 31, 2010. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of 1) the WTI NYMEX crude oil price less a fixed differential approximating $8.15, or 2) heavy oil field postings plus a premium of approximately $1.35.

A widening of commodity differentials may adversely impact our revenues and per barrel economics. Both our produced crude oil and natural gas are subject to pricing in the local markets where the production occurs. It is customary that such products are priced based on local or regional supply and demand factors. California heavy crude sells at a discount to WTI, the U.S. benchmark crude oil, primarily due to the additional cost to refine gasoline or light product out of a barrel of heavy crude. Our Utah light crude also is currently priced at $2.00 below WTI. Natural gas field prices are normally priced off of Henry Hub NYMEX price, the benchmark for U.S. natural gas. While we attempt to contract for the best possible price in each of our producing locations, there is no assurance that past price differentials will continue into the future. Numerous factors may influence local pricing, such as refinery capacity, particularly for black wax crude, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions, governmental regulations, etc. We may be adversely impacted by a widening differential on the products sold.

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 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 pipeline, 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. See firm transportation summary schedule at Item 1 Business.

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Factors that can cause price volatility for crude oil and natural gas include:

- availability and capacity of refineries;
- availability of gathering systems with sufficient capacity to handle local production;
- seasonal fluctuations in local demand for production;
- local and national gas storage capacity;
- interstate pipeline capacity; and
- availability and cost of gas transportation facilities.

Brundage Canyon crude oil production, which is approximately 40 degree API gravity, is sold under contract at WTI less a fixed differential approximating $2.00 per barrel. This contract expires on September 30, 2006. Any new contract will be negotiated based on market prices. We believe the differential has widened by several dollars per barrel. The majority of this crude oil, while light, is a "paraffinic" crude, and can be processed efficiently by only a limited number of stranded inland refineries. The production of this type crude is increasing regionally and beginning to strain the capacity of these refineries. Other new crude sources from the region are pressuring pricing. If these refineries limit the volumes of this parraffinic crude oil they are willing to process, it could impact the marketability of this type of crude which, for Berry, represents approximately 3,500 Bbl/D of production or approximately 15% of total current production. We are investigating the market opportunities for this crude oil. If market prices continue to deteriorate, we may allocate capital expenditures to projects which produce natural gas and crude oils with lower paraffinic content until the refinery constraint is resolved.

We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. 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 provide over half of our steam requirement. These facilities are dependent on reasonable electrical contracts. If, for any reason, we were unable to enter into an electrical contract or were to lose an 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. The financial cost and timing of such investment may adversely affect our production, capital outlays and cash provided by operating activities. We have electricity contracts covering most of our electricity generation which contracts expire in 2009.

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 that we 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. The Company has firm transportation to move 12,000 MMBtu/D on the Kern River Pipeline from the Rocky Mountains to Kern County, CA. This volume is approximately one-third of the Company's current requirement.

Our use of oil and gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in net income. We use hedging transactions with respect to a portion of our oil and gas production to achieve more predictable cash flow and to reduce our exposure to a significant decline in the price of crude oil. While the use of hedging transactions limits the downside risk of price declines, their use may also limit future revenues from price increases. Hedging transactions also involve the risk that the counterparty may be unable to satisfy its obligations. The Company utilizes several counterparties for its hedging contracts.

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 and develop or 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 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. Estimating accumulations of oil and gas is complex. The process 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.

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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 the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

If oil or gas prices decrease, we may be required to take writedowns. We may be required to writedown the carrying value of our oil and gas properties when oil or gas prices are low, including basis differentials, or there are substantial downward adjustments to our estimated proved reserves, increases in estimates of development costs or deterioration in exploration or production results.

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 prices in effect 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 writedown of oil and gas properties is not reversible at a later date even if oil or gas prices increase. See Item 7A Quantitative and Qualitative Disclosures About Market Risk for the Company's hedge position on February 10, 2006.

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 proved undeveloped acreage. Major and independent oil and gas companies actively bid for desirable oil and gas properties, as well as for the equipment and labor required to operate and develop their properties. Many of our competitors have financial resources that are substantially greater, which may adversely affect our ability to compete within the industry.

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. In addition, 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.

The oil and gas business involves many operating risks that can cause substantial losses; 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.

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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. We do not carry business interruption insurance. We may elect not to carry insurance if our Management believes that 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 appropriate insurance coverage 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 federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business. Our development, exploration, production and marketing operations are regulated extensively at the federal, state and local levels. In addition, a portion of our leases in the Uinta Basin are, and some of our future leases may be, regulated by Native American tribes. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. 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. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations oppose certain drilling projects and/or access to prospective lands.

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to the regulation by oil and natural gas-producing states and one Native American tribe of conservation practices and protection of correlative rights. 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 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 or costs could have a negative effect on our ability to explore on or develop its properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

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

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities. Our recent growth is due in part to acquisitions of producing properties, 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 preclosing 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.

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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. Our failure to integrate acquired businesses successfully into our existing business, or the expense incurred in consummating future acquisitions, could result in our incurring unanticipated expenses and losses. In addition, we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant Management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations

Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and operating results.

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, our ability to compete could be harmed.

We have limited control over the activities on properties that we do not operate. Although we operate most of the properties in which we have an interest, other companies operate some of the properties. We have limited ability to influence or control the operation or future development of these nonoperated properties or the amount of capital expenditures that we are required to fund their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

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. In addition, our drilling schedule may vary from our expectations because of future uncertainties and rig availability and access to our drilling locations utilizing available roads. As of December 31, 2005, the Company owns two drilling rigs and has additional one-year contract commitments on

another two drilling rigs. See Note 10 to the financial statements.

We may incur losses as a result of title deficiencies. We purchase working and revenue interests in the oil and natural gas leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available and, often, we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. As is customary in our industry, we rely upon the judgment of oil and natural gas lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected oil and natural gas leases can be generally lost, and the target area can become undrillable.

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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 gas operations. While we have electricity sales contracts in place with the utilities that are currently scheduled to terminate in 2009, legal and regulatory decisions, especially related to the pricing of electricity under the contracts, can adversely affect the economics of our cogeneration facilities and thereby, the cost of steam for use in our oil and gas operations.

Estimates may differ from actual. The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires Management to make estimates and assumptions that affect the reported amounts of assets and liabilities and related disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from these estimates and assumptions used in preparation of its financial statements. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities, the related present value of estimated future net cash flows therefrom, the costs to develop and abandon oil and gas properties, the valuation of derivative positions and stock-based compensation valuation.

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 the Company is, from time to time, a party to certain lawsuits in the ordinary course of business, the Company does not believe any of such existing lawsuits will have a material adverse effect on the Company's 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 of the Registrant. Listed below are the names, ages (as of December 31, 2005) and positions of the executive officers of Berry and their business experience during at least the past five years. All officers of the Company are appointed 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, 52, 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 was the director designated to serve as the presiding director at executive sessions of the Board in the absences of the Chairman and to act as liaison between the independent directors and the CEO. Mr. Heinemann joined the Company’s 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.

RALPH J. GOEHRING, 49, has been Executive Vice President and Chief Financial Officer since June 2004. Mr. Goehring was Senior Vice President from April 1997 to June 2004, and has been Chief Financial Officer since March 1992 and was Manager of Taxation from September 1987 until March 1992. Mr. Goehring is also an Assistant Secretary for the Company.

MICHAEL DUGINSKI, 39, has been Executive Vice President of Corporate Development and California since October 2005. Mr. Duginski was Senior Vice President of Corporate Development from June 2004 through October 2005 and was Vice President of Corporate Development from February 2002 through June 2004. Mr. Duginski, a mechanical engineer, was previously with 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 for the Company.

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LOGAN MAGRUDER, 49, has been Executive Vice President of the Rocky Mountains and Mid-Continent region since October 2005. Mr. Magruder was Senior Vice President of the Rocky Mountain and Mid-Continent region from June 2004 through October 2005 and was Vice President of the Rocky Mountain and Mid-Continent region from August 2003 through June 2004. Mr. Magruder, a petroleum engineer, was a consultant for the Company from February 2003 through August 2003. Mr. Magruder was previously Vice President of U.S. Operations for Calpine Natural Gas Company from 2001 to 2003. Prior to Calpine, Mr. Magruder was employed by Barrett Resources as Vice President of Engineering and Operations from 1996 to 2001.

DAN ANDERSON, 43, has been Vice President of Rocky Mountains and Mid-Continent Production since October 2005. Mr. Anderson was Rocky Mountain and Mid-Continent Manager of Engineering from August 2003 through October 2005. Mr. Anderson was previously a Senior Staff Petroleum Engineer with Williams Production RMT from August 2001 through August 2003. He previously was a Senior Staff Engineer with Barrett Resources from October 2000 through August 2001.

GEORGE T. CRAWFORD, 45, has been Vice President of California Production since October 2005. Mr. Crawford was Vice President of Production from December 2000 through October 2005 and was Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, was previously the Production Engineering Supervisor for Atlantic Richfield Corp. (ARCO) from 1989 to 1998 in numerous engineering and operational assignments including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

BRUCE S. KELSO, 50, has been Vice President of Rocky Mountains and Mid-Continent Exploration since October 2005. Mr. Kelso was Rocky Mountain and Mid-Continent Exploration Manager from August 2003 through October 2005. Mr. Kelso, a petroleum geologist, was previously a Senior Staff Geologist assigned to Rocky Mountain assets with Williams Production RMT, from January 2002 through August 2003. He previously was the Vice President of Exploration and Development at Redstone Resources, Inc. from 2000 to 2001.

BRIAN L. REHKOPF, 58, has been Vice President of Technology since October 2005. Mr. Rehkopf was Vice President of Engineering from March 2000 through October 2005 and was Manager of Engineering from September 1997 to March 2000. Mr. Rehkopf, a registered petroleum engineer, joined the Company’s engineering department in June 1997 and was previously a Vice President and Asset Manager with ARCO since 1992 and an Operations Engineering Supervisor from 1988 to 1992. Mr. Rehkopf is also an Assistant Secretary for the Company.

SHAWN M. CANADAY, 30, has been Treasurer since December 2004 and was 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 ChevronTexaco and in public accounting. Mr. Canaday is also an Assistant Secretary for the Company.

DONALD A. DALE, 59, has been Controller since December 1985.

KENNETH A. OLSON, 50, has been Corporate Secretary since December 1985 and was Treasurer from August 1988 until December 2004.

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 (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 $1.00 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.

In November 1999, the Company adopted a Shareholder Rights Agreement and declared a dividend distribution of one such Right for each outstanding share of Capital Stock on December 8, 1999. Each share of Capital Stock issued after December 8, 1999 includes one Right. The Rights expire on December 8, 2009. See Note 7 to the financial statements.

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Berry's 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 2005 and 2004 are shown below:

	2005			2004		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 66.09	$ 43.85	$ .12	$ 27.30	$ 18.25	$ 0.11
Second Quarter	54.95	40.78	.12	31.07	25.09	0.11
Third Quarter	67.00	52.30	.23	38.44	27.73	0.18
Fourth Quarter	68.66	52.30	.13	50.58	35.16	0.12
Total Dividend Paid			$ .60			$ .52

	February 10, 2006	December 31, 2005	December 31, 2004
Berry’s Common Stock closing price per share as reported on NYSE Composite Transaction Reporting System	$ 68.90	$ 57.20	$ 47.70

The number of holders of record of the Company's Common Stock was 605 as of February 10, 2006. There was one Class B Shareholder of record as of February 10, 2006.

Dividends. The Company paid a special dividend of $.10 per share on September 29, 2005 and increased its regular quarterly dividend by 8%, from $.12 to $.13 per share beginning with the September 29, 2005 dividend. The Company's regular annual dividend is currently $.52 per share, payable quarterly in March, June, September and December. The Company paid a special dividend of $.06 per share on September 29, 2004 and increased its regular quarterly dividend by 9%, from $.11 to $.12 per share beginning with the September 2004 dividend.

Since Berry Petroleum Company's formation in 1985 through December 31, 2005, the Company has paid dividends on its Common Stock for 65 consecutive quarters and previous to that for eight consecutive semi-annual periods. The Company intends to continue the payment of dividends, although future dividend payments will depend upon the Company's level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors. Dividend payments are limited by covenants in the Company's credit facility to the greater of $20 million or 75% of net income.

As of December 31, 2005, dividends declared on 3,984,080 shares of certain Common Stock are restricted, whereby 37.5% of the dividends declared on these shares are paid by the Company to the surviving member of a group of individuals, the B group, for as long as this remaining member shall live.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance

Equity compensation plans approved by security holders	1,625,763	$33.52	1,080,187
Equity compensation plans not approved by security holders	-	-	-

In June 2005, the Company announced that its Board of Directors authorized a share repurchase program for up to an aggregate of $50 million of the Company's outstanding Class A Common Stock. Through December 31, 2005, the Company repurchased 108,900 shares for approximately $6.3 million, which increased diluted earnings by $.01 per share.

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In December 2005, the Company adopted a plan under Rule 10b5-1 of the Securities Exchange Act of 1934 to facilitate the repurchase of its shares of common stock. Rule 10b5-1 allows a company to purchase its shares at times when it would not normally be in the market due to possession of nonpublic information, such as the time immediately preceding its quarterly earnings releases. In addition to share repurchases by the Rule 10b5-1 plan, Berry expects to continue repurchases in the open market from time to time during its normal trading windows. This 10b5-1 plan is authorized under, and is administered consistent with, the Company's $50 million share repurchase program. All repurchases of common stock are made in compliance with regulations set forth by the SEC and are subject to market conditions, applicable legal requirements and other factors.

This program does not obligate the Company to acquire any particular amount of common stock and the plan may be suspended at any time at the Company's discretion.

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares that may yet be purchased under the plans or programs
Third Quarter 2005	43,900	$58.48	43,900	$47,433,000
November 2005	16,300	57.25	16,300	46,500,000
December 2005	48,700	57.80	48,700	43,684,500
Total	**108,900**	**$57.99**	**108,900**	**$43,684,500**

Item 6. Selected Financial Data

The following table sets forth certain financial information with respect to the Company and is qualified in its entirety by reference to the historical financial statements and notes thereto of the Company included in Item 8 Financial Statements and Supplementary Data. The statement of income and balance sheet data included in this table for each of the five years in the period ended December 31, 2005 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data).

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	2005	2004 (3)	2003 (3)	2002 (1) (3)	2001 (1) (3)
Audited Financial Information					
Statement of Income Data:					
Sales of oil and gas	$ 349,691	$ 226,876	$ 135,848	$ 102,026	$ 100,146
Sales of electricity	55,230	47,644	44,200	27,691	35,133
Operating costs - oil and gas production	99,066	73,838	57,830	41,108	34,605
Operating costs - electricity generation	55,086	46,191	42,351	26,747	36,890
Production taxes	11,506	6,431	3,097	2,907	2,479
General and administrative expenses (G&A)	21,396	22,504	14,495	10,417	9.748
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	38,150	29,752	17,258	13,388	13,225
Electricity generation	3,260	3,490	3,256	3,064	3,295
Net income	112,356	69,187	32,363	29,210	20,985
Basic net income per share	5.10	3.16	1.49	1.34	0.96
Diluted net income per share	5.00	3.08	1.47	1.33	0.95
Weighted average number of shares outstanding (basic)	22,041	21,894	21,772	21,741	21,973
Weighted average number of shares outstanding (diluted)	22,490	22,470	22,031	21,902	22,162
Balance Sheet Data:					
Working capital	$ (54,757)	$ (3,840)	$ (3,540)	$ (2,892)	$ 6,314
Total assets	635,051	412,104	340,377	259,325	238,779
Long-term debt	75,000	28,000	50,000	15,000	25,000
Shareholders' equity	334,210	263,086	197,338	172,774	153,590
Cash dividends per share	0.60	0.52	0.47	0.40	0.40
Operating Data:					
Cash flow from operations	187,780	124,613	64,825	57,895	35,433
Exploration and development of oil and gas properties	118,718	71,556	41,061	30,163	14,776
Property/facility acquisitions	112,249	2,845	48,579	5,880	2,273
Additions to vehicles, drilling rigs and other fixed assets	11,762	669	494	469	119
Unaudited Operating Data					
Oil and gas producing operations (per BOE):					
Average sales price before hedging	$ 47.01	$ 33.64	$ 24.48	$ 20.11	$ 19.63
Average sales price after hedging	41.62	30.32	22.52	19.39	19.79
Average operating costs - oil and gas production	11.79	10.09	9.57	7.83	6.86
Production taxes	1.37	.86	.51	.55	.49
G&A	2.55	2.99	2.40	1.98	1.93
DD&A - oil and gas production	4.54	3.96	2.86	2.55	3.28

Production (MBOE)	8,401	7,517	6,040	5,251	5,044
Production (MMWh)	741	776	767	748	483
Proved Reserves Information:					
Total BOE	126,285	109,836	109,920	101,719	102,855
Standardized measure (2)	$ 1,251,380	$ 686,748	$ 528,220	$ 449,857	$ 278,453
Year-end average BOE price for PV10 purposes	48.21	29.87	25.89	24.91	14.13
Other:					
Return on average shareholders' equity	37.63%	31.06%	17.50%	17.90%	14.00%
Return on average total assets	20.15%	18.60%	10.80%	11.70%	8.80%

(1) Information has been revised to reflect the Company's change in allocation of cogeneration costs to oil and gas operations. See Item 7 Management’s Discussion and Analysis.

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(2) See Supplemental Information About Oil & Gas Producing Activities.
(3) Information has been revised to reflect the Company's change in allocation of technical labor and production taxes. See Note 2 to the financial statements.

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

Corporate Strategy. Berry's mission is to increase shareholder value, primarily through increasing the net asset value and maximizing the cash flow and earnings of its assets. The strategies to accomplish these goals include:

- Growing production and reserves from existing assets while managing expenses
- Acquiring more light oil and natural gas assets with significant growth potential in the Rocky Mountain and Mid-Continent region
- Appraising our exploitation and exploration projects in an expedient manner
- Investing our capital in an efficient, disciplined manner to increase production and reserves
- Utilizing joint ventures with respected partners to enter new basins

Notable Items in 2005.

- Achieved record production which averaged 23,015 BOE/D, up 12% from 2004
- Achieved record cash from operating activities of $188 million, up 50% from 2004
- Achieved record net income of $112 million, up 62% from 2004
- 2005 developmental capital expenditures were $131 million, up 82% from 2004
- Acquired and integrated the eastern Colorado Niobrara natural gas producing assets - acquisition cost of $105 million
- Added 24.9 million BOE of reserves before production ending 2005 at 126.3 million BOE
- Achieved reserve replacement rate of 296%
- Negotiated new four-year crude oil sales contract for California heavy oil production
- Observed positive results on Diatomite play and expanded pilot
- Placed price collars on 10,000 barrels per day of future production from 2006 through 2009
- Added approximately 186,000 gross (46,000 net) acres in the North Dakota Bakken play
- Added approximately 624,000 gross (315,000 net) acres to Tri-State area inventory
- Increased quarterly dividend to $.13 per share and paid special dividend of $.10 per share for total payout of $.60 per share
- Began drilling to assess several prospects including Lake Canyon, Coyote Flats and Tri-State area
- Increased financial capacity by establishing a $500 million unsecured credit facility
- Initiated a $50 million share buyback program

Acquisitions. On January 27, 2005, we acquired certain interests in the Niobrara fields in northeastern Colorado for approximately $105 million. At December 31, 2005 the properties consist of approximately 127,000 gross (100,000 net) acres. Production at acquisition was approximately 9 MMcf of natural gas per day, with estimated proved reserves of 87 Bcf. For the month of December 2005, production averaged approximately 13,800 MMcf per day and reserves were 105 Bcf. The acquisition included approximately 200 miles of a pipeline gathering system and gas compression facilities for delivery into interstate gas lines.

In January 2005, we acquired a working interest in eastern Colorado, western Kansas and southwestern Nebraska, from an industry partner. Berry and its partner, will jointly explore and develop shallow Niobrara natural gas, Sharon Springs shale gas and deeper Pennsylvanian formation oil assets on the acreage. We paid approximately $5 million for our working interest in the acreage and believe the potential of the Tri-State area can be exploited by using new

drilling techniques, with 3-D seismic technology, to assess structural complexity, estimate potentially recoverable oil and gas and determine drilling locations.

In 2005, we completed several transactions whereby we now have working interests in 186,000 gross acres (46,000 net) located in the Williston Basin in North Dakota. These lease acquisitions, totaling approximately $11 million, provide us an entry into the emerging Bakken oil play in the Williston Basin. The acreage covers several contiguous blocks located primarily on the eastern flank of the Nesson Anticline. Development activity in the Middle Bakken play is generally expanding to the area surrounding the Nesson Anticline.

In October 2005, we purchased a 50% working interest in approximately 69,000 gross undeveloped acres (24,000 net) in Colorado's Phillips and Sedgwick Counties. This additional Niobrara leasehold position is adjacent to and immediately north of Berry's producing natural gas assets in Yuma County. We expect to begin shooting a 3-D seismic survey and drilling the first delineation wells in 2006.

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On January 27, 2006, we announced an agreement with a private seller to acquire a 50% working interest in natural gas assets in the Piceance Basin of western Colorado for approximately $150 million in cash. Berry internally estimates there are 26 billion cubic feet (Bcf) of proved reserves and has identified over 600 drilling locations based on 10-acre development. We will be the operator in the 6,314 gross acres targeting gas in the Williams Fork section of the Mesaverde formation. We increased the 2006 capital budget by an additional $48 million to $208 million to develop this resource. There are two drilling rigs dedicated to this project, and we will ramp up our drilling activity to four rigs by the end of the year along with complementary services and goods to accelerate the development of this acquisition. Based on the productivity of this acreage and surrounding producing operations, we are seeking to add additional drilling rigs to accelerate development. The transaction closed on February 28, 2006.

Capital Expenditures. Excluding any future acquisitions, in 2006 we plan to spend approximately $208 million. These expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2006, Berry plans to invest approximately $146 million, or 70%, in our Rocky Mountain and Mid-Continent region assets, and $61 million, or 30%, in our California assets. Approximately half the capital budget is focused on converting probable and possible reserves into proved reserves and on our appraisal and exploratory projects.

This robust capital program allows Berry to continue its record activity levels by planning to drill 476 net wells and perform 55 well workover activities in 2006 versus approximately 188 wells and 140 well workovers in 2005. As a result, we are targeting production growth of 12% to average approximately 25,800 BOE per day, which includes the Piceance Basin acquisition, but before any other acquisitions, and we plan to continue to actively appraise significant acreage positions held for hydrocarbon potential. In 2006, we expect production to be approximately 70% heavy oil, 15% light oil and 15% natural gas and anticipate funding our capital program from internally generated cash flow. Successes may also encourage the initiation of additional discretionary projects. We have currently secured the necessary equipment and are meeting permit requirements to achieve the 2006 program.

Appraisal, Evaluation and Exploitation Activity. Since 2003, we have been active in assembling significant acreage positions which we believe are highly prospective for finding and developing commercial quantities of hydrocarbons. This chart depicts our prospective acreage by basin, all of which is in the Rocky Mountain and Mid-Continent region:

Rocky Mountain and Mid-Continent

We plan to appraise five project areas in this region in 2006 for an estimated $23 million budgeted. These five projects are Lake Canyon, Coyote Flats, Big Wash Unit, Tri-State Area and the Bakken Play. We have interests in over one million gross acres, including both productive and prospective, in the Rocky Mountain and Mid-Continent region and the acreage in the five appraisal projects accounts for about 80% of that total.

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Uinta Basin Projects
Lake Canyon - Shallow: On January 13, 2006, we announced commercial success from our first two wells on this acreage. The Nielsen Marsing and Taylor Herrick wells have tested production rates of 98 and 163 BOE/D, respectively, from the same Green River formation that is productive immediately east (approximately 3 miles) in our Brundage Canyon field. Initial performance from these discovery wells suggests that expected reserves per well are on par with the Brundage Canyon field (approximately 80,000 BOE gross) that is currently being developed on 40-acre spacing. Current production from the Taylor Herrick well is not at full capacity as additional facilities are in the process of being installed. Production from the Nielsen Marsing well is selectively limited to two of five completion intervals within the well and will be further optimized by March 2006 when natural gas facilities are completed. We are proceeding with another four wells on the eastern edge of this 169,000 acre block. If the results of these wells are deemed satisfactory, Berry will expand the drilling program and attempt to drill up to another 30 wells over approximately 20,000 acres. The focus will be to begin the methodical appraisal of a sizeable portion of this acreage block. Berry's working interest in these wells will be either 75% or 56.25% depending on the participation of the land owner. The shallow zones are those above the Wasatch which is at approximately 6,500 feet.

Lake Canyon - Deep: Berry's industry partner recently reached total depth of 14,325 feet on its Mesaverde test and set casing to a depth of 11,539 feet. Testing will focus on several Upper Price River and shallower Wasatch intervals where analysis indicates gas potential; the deeper Mesaverde and Blackhawk intervals did not warrant further evaluation. Berry will participate with its industry partner to complete the testing and evaluation of the first deep well on the acreage once pipeline construction into the area is completed, which is currently targeted by May 1, 2006. The second well is scheduled to begin drilling in the fourth quarter of 2006.

Coyote Flats: We will continue to test the viability of the Ferron gas development and Emery CBM pilot with additional drilling.

Big Wash Unit: We will test the shallow oil and deeper gas potential located about two miles southeast of Brundage Canyon.

Denver-Julesburg Basin Projects
Tri-State Area: We will be very active in testing the Niobrara gas potential located in the Tri-State area of Colorado, Kansas and Nebraska. We will participate in 16 exploratory gas wells, drill 11 development wells and acquire additional 3D seismic. Immediately to the north of our producing assets in Yuma County, Colorado, we may drill up to 17 wells based on the acquisition of new seismic data covering the northern acreage.

Williston Basin Projects
Bakken Play: In North Dakota, we intend to participate with up to a 15% working interest in at least four horizontal oil wells to appraise the prospective oil formation.

California-Diatomite
In 2005, oil production from the initial 14 well pilot (6 producers) averaged approximately 135 Bbl/D. Based on promising results from the pilot project, we began an expansion of the pilot with a 25 well program (15 producers) in the third quarter of 2005, and completed it in the fourth quarter. We continue to assess the long-term economic and operating viability of the project as the early wells are an indication of future large-scale development. Results are in accordance with expectations. We are judiciously monitoring the steam to oil ratio (SOR) because we believe achieving an SOR of 6 or less is the threshold for commerciality. SOR measures how much steam is required for injection into the reservoir to produce one barrel of oil. Estimated original oil in place ranges between 200 million to

250 million barrels with targets of a minimum 25% recovery of original oil in place. In 2005, we booked 2.5 million BOE of reserves based on asset performance. We believe that the project continues to remain on track towards commerciality.

In 2006, we are expanding the commercial test of our diatomite resource by investing approximately $25 million in a program that will add another 50 wells (31 producers, 16 steam injectors, and 3 service wells). Since completing our expansion of the initial pilot in December 2005, we now have a total of 39 wells (21 producers, 15 steam injectors, and 3 service wells) that we will be using to monitor reservoir performance. In addition to the drilling program, we will add significant facilities including steam generation equipment and will be optimizing the pattern configuration and layout for the eventual full-field development if commerciality is determined.

Development Activity

Rocky Mountain and Mid-Continent
Approximately $93 million will be invested in this region, with $58 million targeting the continued development drilling of the Green River formation at Brundage Canyon to assist full development and will include a 20-acre spacing pilot. In northeastern Colorado, $17 million will be invested to acquire additional seismic data and drill 150 wells to further develop the Niobrara natural gas production from our producing assets.

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California
Berry will invest $37 million in its heavy oil properties, utilizing horizontal well and new steam-optimization technologies to maximize recovery from our legacy assets. Development activity at our Poso Creek, Ethel D and Midway-Sunset assets will utilize improved application of steam flood technology to provide production growth.

See Item 1 Business for more information on Development Activity.

Obstacles and Risks to Accomplishment of Strategies and Goals. See Item 1A Other Factors Affecting the Company's Business and Financial Results for a detailed discussion of factors that affect our business, financial condition and results of operations.

Results of Operations. Approximately 86% of Berry's revenues are generated through the sale of oil and natural gas production under either negotiated contracts or spot gas purchase contracts at market prices. Over 83% of these volumes are from oil production, and the majority of those volumes are from heavy oil production in California. The remaining 14% of Berry's revenues are derived from electricity sales from cogeneration facilities which supply over half of Berry's steam requirement for use in its California thermal heavy oil operations. We have invested in these facilities for the purpose of lowering our steam costs which are significant in the production of heavy crude oil.

Revenues. Sales of oil and gas were up 54% in 2005 compared to 2004 and up 157% from 2003. This significant improvement was due to increases in both oil and gas prices and production levels.

Improvements in production volume are due to acquisitions and sizable capital investments. Improvement in prices during 2005 are due to a tighter supply and demand balance and the nervousness of the market about possible supply disruptions. The increase in oil prices contributed roughly two-thirds of the revenue increase and the increase in production volumes contributed the other third. Approximately 84% of Berry's oil and gas sales volumes in 2005 were crude oil, with 78% of the crude oil being heavy oil produced in California which was sold under a contract based on the higher of WTI minus a fixed differential or the average posted price plus a premium. This contract ended on January 31, 2006. The contract allowed us to improve our California revenues over the posted price by approximately $38 million and $13 million in 2005 and 2004, respectively.

On November 21, 2005, we entered into a new crude oil sales contract for our California production for deliveries beginning February 1, 2006. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of 1) the WTI NYMEX crude oil price less a fixed differential approximating $8.15, or 2) heavy oil field postings plus a premium of approximately $1.35. The initial term of the contract is for four years with a one-year renewal at our option. The agreement effectively eliminates our exposure to the risk of a widening WTI to California heavy crude price differential and

allows us to effectively hedge our production based on WTI pricing similar to the previous contract. Initial deliveries under the contract are approximately 15,000 net barrels per day or approximately two-thirds of Berry's total production.

Brundage Canyon crude oil production, which is approximately 40 degree API gravity, is sold under contract at WTI less a fixed differential approximating $2.00 per barrel. This contract expires on September 30, 2006. Any new contract will be negotiated based on market prices. We believe the differential has widened by several dollars per barrel. The majority of this crude oil, while light, is a “paraffinic” crude, and can be processed efficiently by only a limited number of stranded inland refineries. The production of this type crude is increasing regionally and beginning to strain the capacity of these refineries. Other new crude sources from the region are pressuring pricing. If these refineries limit the volumes of this parraffinic crude oil they are willing to process, it could impact the marketability of this type of crude which, for Berry, represents approximately 3,500 Bbl/D of production or approximately 15% of total current production. We are investigating the market opportunities for this crude oil. If market prices continue to deteriorate, we may allocate capital expenditures to projects which produce natural gas and crude oils with lower paraffinic content until the refinery constraint is resolved.

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The following companywide results are in millions (except per share data) for the years ended December 31:

	2005	2004	2003
Sales of oil	$ 289	$ 210	$ 130
Sales of gas	61	17	6
Total sales of oil and gas	$ 350	$ 227	$ 136
Sales of electricity	55	48	44
Interest and other income, net	2	-	1
Total revenues and other income	$ 407	$ 275	$ 181
Net income	$ 112	$ 69	$ 32
Earnings per share (diluted)	$ 5.00	$ 3.08	$ 1.47

Reserve Replacement Rate. The reserve replacement rate is calculated by dividing total new proved reserves added for the year by total production for the year. This measure is important because it is an indication of growth in proved reserves of the Company and, thus may impact the value of the Company. We believe our calculation of this measure is substantially similar to how other companies compute reserve replacement rate.

Hedging. See Item 7A Quantitative and Qualitative Disclosures about Market Risk and Note 15 to the financial statements.

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Operating data. The following table is for the years ended December 31:

	2005	%	2004	%	2003	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	16,063	70	15,901	77	15,477	94
Light Oil Production (Bbl/D)	3,336	14	3,345	16	489	3
Total Oil Production (Bbl/D)	19,399	84	19,246	93	15,966	97
Natural Gas Production (Mcf/D)	21,696	16	7,752	7	3,499	3
Total (BOE/D)	23,015	100	20,537	100	16,549	100
Percentage increase from prior year	12%		24%		15%	
Per BOE:						
Average sales price before hedging	$ 47.01		$ 33.64		$ 24.48	
Average sales price after hedging	41.62		30.32		22.52	
Oil, per Bbl:						
Average WTI price	$ 56.70		$ 39.21		$ 31.16	
Price sensitive royalties	(4.42)		(2.78)		(1.79)	
Gravity differential	(5.22)		(4.93)		(2.97)	
Crude oil hedges	(6.21)		(2.93)		(2.03)	
Average oil sales price after hedging	$ 40.85		$ 28.57		$ 24.37	
Gas, per MMBtu:						
Average Henry Hub price	$ 8.05		$ 6.13		$ 5.11	
Natural gas hedges	(.11)		(.01)		.02	
Location and quality differentials	(1.45)		(.63)		(.81)	
Average gas sales price after hedging	$ 6.49		$ 5.49		$ 4.32	

Electricity. Berry consumes natural gas as fuel to operate its three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the economic production of heavy oil. We sell our electricity to utilities under Standard Offer contracts, under which our revenues are linked to the cost of natural gas. Natural gas index prices are the primary determinant of Berry's electricity sales price. The correlation between electricity sales and natural gas prices allows us to more effectively manage our cost of producing steam. Revenue and operating costs in the year ended 2005 were up from the year ended 2004 due to 18% higher electricity prices and 34% higher natural gas prices, respectively. We purchased approximately 38 MMBtu/D as fuel for use in our cogeneration facilities in the year ended December 31, 2005.

	2005	2004	2003
Electricity			
Revenues (in millions)	$ 55.2	$ 47.6	$ 44.2
Operating costs (in millions)	$ 55.1	$ 46.2	$ 42.4
Decrease to total oil and gas operating expenses-per barrel	$ .02	$ .19	$ .32
Electric power produced - MWh/D	2,030	2,121	2,100

Electric power sold - MWh/D	1,834	1,915	1,925
Average sales price/MWh before hedging	$ 82.73	$ 70.24	$ 62.91
Average sales price/MWh after hedging	$ 82.73	$ 70.24	$ 61.95
Fuel gas cost/MMBtu (after hedging and excluding transportation)	$ 7.30	$ 5.46	$ 4.88

Royalties. A price-sensitive royalty burdens a portion of our Midway-Sunset California property which produces approximately 3,800 barrels per day. This royalty is 75% of the amount of the heavy oil posted price above a base price which was $15.18 in 2005. This base price escalates at 2% annually, thus the threshold price is $15.48 per barrel in 2006. Amounts paid were $29 million, $19.3 million and $10.2 million in the years ended December 31, 2005, 2004 and 2003, respectively. Accounts payable associated with this royalty at year end 2005 was $29 million. Because our interest in the revenue varies according to crude prices, the continuing development on this property will depend on its future profitability.

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A second price sensitive royalty burdens approximately 700 barrels per day at our Placerita field in California. This royalty is calculated when the sales price exceeds $26 per barrel up to a maximum. The royalty was $2.8 million, $1.4 million and $.3 million in the years ended December 31, 2005, 2004 and 2003, respectively. The maximum amount of the royalty over its life is $5 million, thus, we expect this royalty payable will end in the first quarter of 2006.

In 2005, the Bureau of Land Management revoked their royalty exemption for certain heavy oil properties. This resulted in a reduction to Berry of .9 million barrels of reserves and approximately 100 BOE/D in the fourth quarter of 2005. In December 2004, certain royalty owners exercised their right to convert their royalty interest into a working interest on our Formax property in the Midway-Sunset field. This resulted in a reduction of 1.8 million barrels of reserves and represented approximately 450 BOE/day as of December 31, 2004.

Oil and Gas Operating, Production Taxes, G&A and Interest Expenses. We believe that the most informative way to analyze changes in recurring operating expenses from one period to another is on a per unit-of-production, or BOE, basis. The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2005:

	Amount per BOE			Amount (in thousands)		
	2005	2004	Change	2005	2004	Change
Operating costs - oil and gas production	$ 11.79	$ 10.09	17%	$ 99,066	$ 73,838	34%
Production taxes	1.37	.86	59%	11,506	6,431	79%
DD&A - oil and gas production	4.54	3.96	15%	38,150	29,752	28%
G&A	2.55	2. 99	(15)%	21,396	22,504	(5)%
Interest expense	0.72	0.27	167%	6,048	2,067	193%
Total	$ 20.97	$ 18.17	15%	$ 176,166	$ 134,592	31%

Our total operating costs, production taxes, G&A and interest expenses for 2005, stated on a unit-of-production basis, increased 15% over 2004. The changes were primarily related to the following items:

- Operating costs: Higher crude oil and natural gas prices have created an incentive for the U.S. domestic oil and gas industry to significantly increase exploration and development activities, which is straining the capacity for goods and services that support our industry. Thus, higher costs are prominent throughout the industry and resulted in higher operating costs per BOE for the year ended 2005 as compared to 2004. Costs in California were also higher due to increased well servicing activities and increases in steam costs. The cost of Berry's steaming operations on our heavy oil properties represents a significant portion of our operating costs and will vary depending on the cost of natural gas used as fuel and the volume of steam injected. The following table presents steam information:

	2005	2004	Change
Average volume of steam injected (Bbl/D)	70,032	69,200	1%
Fuel gas cost/MMBtu	$7.30	$5.46	34%

As commodity prices remain robust, we anticipate that cost pressures within our industry may continue. Natural gas prices impact our cost structure in California by approximately $1.75 per California BOE for each $1.00 move in natural gas price. The California production target for 2006 is 16,700 BOE/D.

- Production taxes: Higher prices, such as those exhibited in 2005, create increased production taxes.

- Depreciation, depletion and amortization: DD&A increased per BOE in the year ended 2005 from the year ended 2004 due to higher acquisition costs of our Rocky Mountain and Mid-Continent region assets as compared to our legacy heavy oil assets in California and higher finding and development costs. As these costs increase, our DD&A rates per BOE will also increase.

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- General and administrative: Approximately two-thirds of Berry's G&A is compensation or compensation related costs. We intend to remain competitive in workforce compensation to achieve our growth plans. Stock-based compensation expense was $.35 per BOE and $.56 per BOE for the years ended December 31, 2005 and 2004, respectively. Compensation expenses increased due to increased staffing resulting from our growth, and increases in compensation levels and bonuses. Additionally, we incurred increased legal and accounting fees, primarily due to compliance with Sarbanes-Oxley, and growth through acquisitions and other financial reporting related matters. Legal and accounting expenses were $.28 per BOE in 2005 as compared to $.23 per BOE in 2004.

- Interest expense: We increased our outstanding borrowings to $75 million at December 31, 2005 as compared to $28 million at December 31, 2004. Average borrowings increased as a result of acquisitions of $112 million during 2005. Additionally, interest rates have increased by approximately 1.75% since December 31, 2004.

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2004:

	Amount per BOE			Amount (in thousands)		
	2004	2003	Change	2004	2003	Change
Operating costs - oil and gas production	$ 10.09	$ 9.57	5%	$ 73,838	$ 57,830	28%
Production taxes	.86	.51	69%	6,431	3,097	108%
DD&A - oil and gas production	3.96	2.86	38%	29,752	17,258	72%
G&A	2.99	2.40	25%	22,504	14,495	55%
Interest expense	0.27	0.23	17%	2,067	1,414	46%
Total	$ 18.17	$ 15.57	17%	$ 134,592	$ 94,094	43%

Our total operating, production taxes, G&A and interest expenses for 2004, stated on a unit-of-production basis, increased 17% over 2003. The changes were primarily related to the following items:

· Operating costs: 2004, on a per barrel basis, increased over 2003 due primarily to higher steam costs. The cost of Berry's steaming operations for its heavy oil properties represents a significant portion of our operating costs and will vary depending on both the cost of natural gas used as fuel and the volume of steam injected during the year. The following table presents steam information:

	2004	2003	Change
Average volume of steam injected (Bbl/D)	69,200	63,300	9%
Fuel gas cost/MMBtu	$5.46	$4.88	12%

· Depreciation, depletion and amortization: 2004 was higher due to higher finding and development costs, the shorter reserve life of our Brundage Canyon properties in Utah and the cumulative effect of increased development activities in recent years. We expect DD&A to trend higher over the next few years due to the shorter reserve life of the Rocky Mountain assets compared to our California properties and continued development of our California and Rocky Mountain properties.

· General and administrative: 2004 was up from 2003 due to stock-based compensation costs increasing by $2.8 million in 2004, or $.56 per BOE, which are primarily non-cash charges resulting from marked-to-market adjustments under the variable method of accounting prior to the change of certain exercise provisions of our stock option plan on July 29, 2004 and non-cash compensation expense under the fair value method of accounting. Compensation expenses increased due to increased staffing resulting from our growth, an increase in compensation levels and bonuses and costs related to a change in chief executive officers. Additionally, we incurred increased legal and accounting fees during 2004, primarily due to compliance with Sarbanes-Oxley and other financial reporting related matters.

· Interest expense: 2004 was up from 2003. Although our borrowings at year-end 2004 were $28 million, down from $50 million in 2003, we borrowed $40 million in August 2003 to fund the acquisition of our Brundage Canyon property. We reduced our debt from 2003 levels during the latter half of 2004.

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Estimated 2006 Oil and Gas Operating, G&A and Interest Expenses

		Amount per BOE	
	Anticipated range in 2006	2005	2004
Operating costs-oil and gas production (1)	$ 13.00 to 16.00	$ 11.79	$ 10.09
Production taxes	1.35 to 1.65	1.37	.86
DD&A	5.75 to 6.50	4.54	3.96
G&A	2.75 to 3.00	2.55	2.99
Interest expense	1.35 to 1.60	0.72	.27
Total	$ 24.20 to 28.75	$ 20.97	$ 18.17

(1) Assuming natural gas prices of approximately NYMEX HH $8.50 MMBtu, we plan to inject steam at levels in 2006 comparable to, or slightly higher than 2005 levels.

Dry hole, abandonment and impairment. The $5.7 million reflected on Berry's income statement under dry hole, abandonment and impairment is made up of the following three items:

- At December 31, 2004, we were in the process of drilling one exploratory well on our Midway-Sunset property and one exploratory well on our Coyote Flats prospect. These two wells were determined non-commercial in February 2005 and $2.2 million was incurred and expensed in 2005.
    - Two exploratory wells at northern Brundage Canyon were expensed for $.6 million.
- Finally, we impaired the remaining carrying value of our Illinois and eastern Kansas prospective CBM acreage acquired in 2002 by $2.9 million.

Costs of $.7 million which were incurred on the Midway-Sunset property and the exploratory well on the Coyote Flats prospect as of December 31, 2004 were charged to expense. During 2003, we recorded a pre-tax write down of $4.2 million related to two CBM pilot projects.

Exploration costs. We incurred exploration costs of $3.6 million in 2005 compared to zero costs in 2004 and 2003. These costs consist primarily of geological and geophysical costs. Berry participated in 3-D seismic surveys at Lake Canyon, Utah and in the Tri-State area. We are projecting exploration costs in 2006 of between $4 million and $6 million.

Income Taxes. The Revenue Reconciliation Act of 1990 included a tax credit for certain costs associated with extracting high-cost, capital-intensive marginal oil or gas and which utilizes at least one of nine designated "enhanced" or tertiary recovery methods (EOR). Cyclic steam and steam flood recovery methods for heavy oil, which Berry utilizes extensively, are qualifying EOR methods. In 1996, California conformed to the federal law, thus, on a combined basis, we are able to achieve credits approximating 12% of our qualifying costs. The credit is earned only for qualified EOR projects by investing in one of three types of expenditures: 1) drilling development wells, 2) adding facilities that are integrally related to qualified EOR production, or 3) utilizing a tertiary injectant, such as steam, to

produce oil. The credit may be utilized to reduce our tax liability down to, but not below, our alternative minimum tax liability. This credit has been significant through 2005 in reducing our income tax liabilities and effective tax rate. However, with higher crude oil prices and the increasing investment in its light crude oil and natural gas properties, Berry's effective income tax rate trended higher in 2005 compared to prior years. The average U.S. wellhead price for crude oil exceeded $43 in 2005, thus triggering a full phase-out of the EOR credit for 2006. If the U.S. wellhead price of crude oil declines below the triggering point in future years, we will be able to claim the EOR credit on qualifying expenditures and our effective tax rate should decline. As of December 31, 2005 the Company has approximately $23 million of federal and $17 million of state (California) EOR tax credit carryforwards available to reduce future income taxes. The EOR credits will begin to expire, if unused, in 2024 and 2015 for federal and California, respectively.

We experienced an effective tax rate of 31%, 23% and 12% reported in 2005, 2004 and 2003, respectively. The increase in effective tax rate during 2005 is primarily due to a much higher (over 80%) pre-tax income in relation to consistent EOR credits in 2005 over 2004. Our expansion outside of California and investment in non-thermal projects are also key factors in the increase. We have been able to achieve an effective tax rate below the statutory tax rate of approximately 40% through 2005 primarily as a result of significant EOR tax credits earned by our continued investment in the development of thermal EOR projects, both through capital expenditures and continued steam injection. We expect our effective tax rate will be higher as the EOR credit will be non-existent for 2006 and possibly later years, and we expect to have an effective tax rate in the 37% to 39% range in 2006, based on WTI prices averaging between $50 and $70. See Note 9 to the financial statements for further information.

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Financial Condition, Liquidity and Capital Resources. Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development and exploration drilling and the acquisition of properties. Fluctuations in commodity prices have been the primary reason for short-term changes in our cash flow from operating activities. The net long-term growth in our cash flow from operating activities is the result of growth in production as affected by period to period fluctuations in commodity prices.

Capital Expenditures. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes. Excess cash generated from operations is expected to be applied toward acquisitions, debt reduction or other corporate purposes.

Excluding any future acquisitions, in 2006 we plan to spend approximately $208 million on capital projects and anticipate funding these expenditures from internally generated cash flow. These expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2006, Berry plans to invest approximately $146 million, or 70%, in our Rocky Mountain and Mid-Continent region assets, and $61 million, or 30%, in our California assets. Approximately half the capital budget is focused on converting probable and possible reserves into proved reserves and on our appraisal and exploratory projects. Total capital expenditures in 2005, excluding acquisitions, were $119 million and included the drilling of approximately 188 new wells and completing 140 workovers on our properties. All capital expenditures, excluding acquisitions, were funded out of internally generated cash flow. See Item 1 Business for further details.

Dividends. The regular quarterly dividend was increased by 8%, from $.12 to $.13 per share, beginning with the September 2005 dividend. The total dividend payable on September 29, 2005 was $.23 per share which included a special $.10 per share dividend. This is the third consecutive year that we have raised the quarterly dividend and distributed a special dividend. This action resulted in a total payout in 2005 of $.60 per share, up 16% from the $.52 per share paid out in 2004 and up 28% from the $.47 per share paid out in 2003.

Working Capital and Cash Flows. Cash flow from operations is dependent upon the price of crude oil and natural gas and our ability to increase production and manage costs. Crude oil and natural gas prices increased in 2005 (see graphs on page 30) and we increased production by 12%.

Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit arrangements. We used our long-term borrowings under our credit facility primarily to fund property acquisitions. Generally, we use excess cash to pay down borrowings under our credit arrangement. As a result, we often have a working capital deficit or a relatively small amount of positive working capital. In 2005, the working capital deficit was substantially greater than 2004. The deficit is primarily made up of changes in the following four balance sheet accounts from 2005 as compared to 2004; a $14.7 million decrease in cash, an $11 million increase in the Formax royalty payable, an $11.5 million increase in the short-term line of credit which is used to improve cash management and a $9 million increase in fair value of derivatives (net liability) which is associated with our increased use of hedging in 2005.

The table below compares financial condition, liquidity and capital resources changes for the years ended December 31 (in millions, except for production and average prices):

	2005	2004	Change
Production (BOE/D)	23,015	20,537	+12%

Average oil and gas sales prices, per BOE after hedging	$ 41.62	$ 30.32	+37%
Net cash provided by operating activities	$ 188	$ 125	+50%
Working capital	$ (54.8)	$ (3.8)	(134)%
Sales of oil and gas	$ 350	$ 227	+54%
Long-term debt	$ 75	$ 28	+168%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 231	$ 85.3	+171%
Dividends paid	$ 13.2	$ 11.4	+16%

In June 2005, a share repurchase program was authorized for up to an aggregate of $50 million of Berry's outstanding Class A Common Stock. Through December 31, 2005, we had repurchased 108,900 shares for approximately $6.3 million. See Note 7 to the financial statements.

Hedging. See Item 7A Quantitative and Qualitative Disclosures about Market Risk and Note 15 to the financial statements.

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Credit Facility. See Note 6 to the financial statements for more information. We have a $500 million unsecured credit facility, which has a current borrowing base of $350 million and is an integral part of our financing structure that provides improved access to capital and the flexibility to support growth plans.

Contractual Obligations. Refer to Note 10 to the financial statements.

Application of Critical Accounting Policies. The preparation of financial statements in conformity with generally accepted accounting principles requires Management to make estimates and assumptions for the reporting period and as of the financial statement date. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities and the reported amounts of revenues and expenses. Actual results could differ from those amounts.

A critical accounting policy is one that is important to the portrayal of the Company's financial condition and results, and requires Management to make difficult subjective and/or complex judgments. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. The Company believes the following accounting policies are critical policies.

Successful Efforts Method of Accounting. The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion. Exploratory wells that discover potentially economic reserves that are in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized as long as the additional exploratory work is under way or firmly planned.

Oil and Gas Reserves. Oil and gas reserves include proved reserves that represent estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The Company's oil and gas reserves are based on estimates prepared by independent engineering consultants. Reserve engineering is a subjective process that requires judgment in the evaluation of all available geological, geophysical, engineering and economic data. Projected future production rates, the timing of future capital expenditures as well as changes in commodity prices may significantly impact estimated reserve quantities. Depreciation, depletion and amortization (DD&A) expense and impairment of proved properties are impacted by the Company's estimation of proved reserves. These estimates are subject to change as additional information and technologies become available. Accordingly, oil and natural gas quantities ultimately recovered and the timing of production may be substantially different than projected. Reduction in reserve estimates may result in increased DD&A expense, increased impairment of proved properties and a lower standardized measure of discounted future net cash flows.

Carrying Value of Long-lived Assets. Downward revisions in the Company’s estimated reserve quantities, increases in future cost estimates or depressed crude oil or natural gas prices could cause the Company to reduce the carrying amounts of its properties. The Company performs an impairment analysis of its proved properties annually by comparing the future undiscounted net revenue per the annual reserve valuation prepared by the Company’s independent reserve engineers to the net book carrying value of the assets. An analysis of the proved properties will also be performed whenever events or changes in circumstances indicate an asset’s carrying value may not be

recoverable from future net revenue. Assets are grouped at the field level and if it is determined that the net book carrying value cannot be recovered by the estimated future undiscounted cash flow, they are written down to fair value. Cash flows used in the impairment analysis are determined based on Management’s estimates of crude oil and natural gas reserves, future crude oil and natural gas prices in effect at the end of the period and costs to e