BERRY PETROLEUM CO
Form 10-K
March 31, 2005

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, 2004**
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**

(Former name, former address and former fiscal year, if changed since last report)

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 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 an accelerated filer (as defined in Rule 12b-2 of the Act). YES x NO o

As of June 30, 2004, the aggregate market value of the voting stock held by non-affiliates was $519,158,260. As of March 14, 2005, the registrant had 21,119,120 shares of Class A Common Stock outstanding. The registrant also had 898,892 shares of Class B Stock outstanding on March 14, 2005 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**

Company Website

The Company has a website located at http://www.bry.com. The website can be used to access recent news releases and Securities and Exchange Commission 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. The contents of the Company's website are not incorporated into this document. Securities and Exchange Commission filings, including supplemental schedules and exhibits can also be accessed free of charge through the SEC website at http://www.sec.gov.

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 the San Joaquin Valley, Los Angeles and Ventura Basins in California, the Uinta Basin in northeastern Utah and the Denver-Julesburg Basin in Colorado, Kansas and Nebraska. The Company’s corporate headquarters are located in Bakersfield, California. The Company has a regional office in Denver, Colorado to manage its assets in the Rocky Mountain and Mid-Continent regions. Management believes that these facilities are adequate for its current operations and anticipated growth. Information contained in this report on Form 10-K reflects the business of the Company during the year ended December 31, 2004 unless noted otherwise.

The Company's mission is to increase shareholder value, primarily through maximizing the value and cash flow of the Company's assets. To achieve this, Berry's corporate strategy is to increase its net proved reserves annually, grow production annually and, in the process, increase both net income and cash flow in total and per share. To increase proved reserves and production, the Company will compete to acquire oil and gas properties with principally proved reserves and exploitation potential or sizeable acreage positions that the Company believes can ultimately contain substantial reserves which can be developed at reasonable costs. Additionally, the Company will continue to focus on the further development of its properties through developmental drilling, well completions, remedial work and by application of enhanced oil recovery (EOR) methods, as applicable. In conjunction with the goals of maximizing profitability and the exploitation and development of its substantial heavy crude oil base in California, 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. Berry views these assets as a key part of its long-term success. Berry believes that its primary strengths are its ability to maintain a cost-efficient operation, its ability to acquire attractive producing properties which have significant development, exploitation and enhancement potential and sizable prospective acreage blocks in or near producing areas, its strong financial position and its experienced management team and staff. The Company has identified the Rocky Mountain and Mid-Continent regions as its primary areas of interest for growth. The Company believes that it can be successful in growing its reserve base and production in a profitable manner by investing in certain assets in these regions and California. Additionally, it provides substantial opportunity for the Company to diversify its existing predominantly heavy crude oil base into light oil and natural gas. Strategically, the Company desires to increase its natural gas reserves and production as the Company consumes approximately 37,000 MMBtu daily as fuel for steam generation which is utilized in its California heavy oil operations. The Company has an unsecured credit facility with a current borrowing base of $200 million (at year-end 2004, $172 million is available) which may be utilized in adding reserves and production through acquisitions.

Proved Reserves

As of December 31, 2004, the Company's estimated proved reserves were 110 million barrels of oil equivalent, (BOE), of which 87% are heavy crude oil, 9% light crude oil and 4% natural gas. A significant portion of these proved reserves are owned in fee. Geographically, 88% of the Company’s reserves are located in California and 12% in the Rocky Mountain region. Proved undeveloped reserves make up 26% of the Company's proved total. The projected capital to develop these reserves is $114 million, at an estimated cost of approximately $4.00 per BOE. Over 90% of the capital to develop these reserves is expected to be expended in the next five years. Production in 2004 was 7.5 million BOE, up 25% from production of 6.0 million BOE in 2003. Based on average daily fourth quarter production for each year, the Company’s reserves-to-production ratio was 14.1 years at year-end 2004, reduced from 16.2 years at year-end 2003. This reduction is primarily due to the shorter reserve life of the Company's Rocky Mountain assets compared to its California assets.

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Acquisitions

The Company actively pursued its growth strategy during the year. In September 2004, the Company and an industry partner were the successful bidders on certain leases offered by the Bureau of Land Management (BLM). These leases representing approximately 17,000 gross (8,500 net) acres are located southeast of the Company's Brundage Canyon producing properties. The issuance of leases for this acreage is subject to final approval by the BLM. The Company paid approximately $3.3 million for its interest in this acreage, which is included in other non-current assets on the Company's Balance Sheet as of December 31, 2004.

In July 2004, the Company and Bill Barrett Corporation, entered into a joint exploration and development agreement with the Ute Indian Tribe to explore and develop approximately 124,500 gross (62,250 net) prospective acres of tribal lands in the Uinta Basin in Utah. The Company also purchased an interest in 44,500 gross (22,250 net) acres of privately owned lands near this tribal acreage. The 169,000 gross acre block 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 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. This acquisition is a strategic fit as it builds on the Company's success at Brundage Canyon and increases the potential for the discovery of additional light oil and natural gas. The Company's minimum obligation under its exploration and development agreement is $10.5 million.

In December 2004, the Company signed a development agreement with Petro-Canada Resources (USA) Inc., to develop Petro-Canada's Coyote Flats prospect in Utah, approximately 45 miles southwest of the Company's Brundage Canyon producing properties. Berry will be the operator and upon completing a defined drilling program, will own an interest in approximately 69,250 gross (33,500 net) undeveloped acres. The Company estimates its total cost under this agreement will be approximately $10.3 million which will vary based on drilling costs. Upon completion of the program, the Company and its 50% partner, Petro-Canada Resources, will jointly determine future development plans.

In December 2004 the Company announced and, in January 2005, completed the acquisition of certain natural gas producing assets in the Niobrara field located in eastern Colorado for approximately $105 million utilizing the Company's existing credit facility. These properties consist of approximately 127,000 gross (69,500 net) acres. The Company has a working interest of approximately 52%. Production, as of March 1, 2005, is 9 MMcf (million cubic feet) of natural gas per day net to Berry's interest, with estimated proved natural gas reserves of 87 Bcf (billion cubic feet).

In January 2005, the Company purchased from Bill Barrett Corporation a working interest in approximately 390,000 gross (172,250 net) prospective acres located in eastern Colorado, western Kansas and southwestern Nebraska (the Tri-State acreage). The Company and its 50% partner will jointly explore and develop shallow Niobrara biogenic natural gas, Sharon Springs Shale gas and deeper Pennsylvanian formation oil assets on the acreage. The Company paid approximately $5 million for its working interest in the acreage. The Company believes 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.

2005 Outlook

The Company is targeting a 12% increase in production in 2005 which includes the production from the Niobrara gas assets. Additionally, crude pricing looks very favorable for 2005. Additionally, the Company maintains a hedging program which is designed to moderate the effects of a severe crude oil price downturn and protect certain operating margins in the Company's California operations. The Company has approximately 7,750 barrels per day hedged for calendar 2005 at approximately NYMEX West Texas Intermediate (WTI) of $40.75 per barrel. The Company's existing hedge position can be viewed on its website at: http://www.bry.com/index.php?page=hedging. The contents of the Company's website are not incorporated into this document

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Excluding any future acquisitions, in 2005 the Company plans to spend approximately $107 million on drilling 177 net wells and performing 92 workovers. The Company intends to fund 100% of its capital program out of internally generated cash flow. Major areas of focus in 2005 will be:

- California production - Projects include expanding the thermal development of the Poso Creek field, the evaluation of the Company's diatomite pilot at North Midway-Sunset and additional drilling of infill horizontal wells at South Midway-Sunset.

- Rockies & Mid-Continent production - In 2005, the Company will continue the development of the Brundage Canyon producing property on 80-acre spacing, test the potential of 40-acre infill drilling and appraise the northern and southern limits of the field. On the recently acquired Niobrara gas assets, the Company plans to drill approximately 60 wells as part of its ongoing development program and the initiation of the 40-acre infill program from the existing 80-acre development.

- Rockies & Mid-Continent prospects - The Company and its joint venture partner, will begin testing the oil potential of the Lake Canyon acreage with at least two shallow test wells at approximately 6,000 feet in the Green River trend. These initial drill sites will be approximately three miles west of the Company's Brundage Canyon producing property and have the potential of providing the Company with development opportunities comparable to Brundage Canyon. Drilling of the first deep natural gas test well in Lake Canyon is scheduled for the fourth quarter of 2005. The Company intends to drill its obligation wells at Coyote Flats, (45 miles southwest of Brundage Canyon) which will target the Ferron sands and Emery coals. Additionally, the Company will participate with its partner to begin testing the Sharon Springs Shale gas, Niobrara biogenic natural gas, along with the deeper Pennsylvanian formation oil prospects in its recently acquired Tri-State acreage in Colorado, Nebraska and Kansas.

    - In September 2004, the Company entered into a farm-out agreement pursuant to which Bill Barrett Corporation had the right to earn a 75% working interest in the deep Mesaverde formation and deeper horizons within the Brundage Canyon field by drilling a deep exploratory test. The Company's partner commenced the drilling of its initial deep exploratory well in Brundage Canyon in November 2004 and abandoned it in January 2005, pending the further evaluation of a 3-D seismic survey and assessment of optimal completion technology. No costs were incurred by the Company related to the drilling or abandonment of this well.

Operations

Berry operates all of its principal oil and gas producing properties. In California, the Midway-Sunset, Poso Creek and Placerita 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 well-bore for production. Berry utilizes cyclic steam and/or steam flood recovery methods in all of these fields and 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 thus the reservoir temperature is high enough to produce the oil without the assistance of additional heat from steam. In Utah, the Brundage Canyon field consists of light gravity crude and associated natural gas produced from a depth of approximately 6,000 feet.

In California, 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 lease automatic custody transfer units or gauged before sale and subsequently transferred into crude oil pipelines owned by other companies or transported via truck. 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 pipelines to two main shipper pipelines.

Natural gas produced from the Niobrara gas assets is transported by Company and third party distribution lines to two main shipper pipelines.

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Revenues

Total revenues for 2004 increased by $94 million or 52% over 2003. Total revenues and the percentage of revenues by source for the prior three years are as follows:

	2004	2003	2002
Total revenues (in millions)	$ 275	$ 181	$ 131
Sales of oil and gas	83%	75%	78%
Sales of electricity	17%	24%	21%
Other	-	1%	1%

Crude Oil and Natural Gas Marketing

The global and California crude oil markets continue to remain strong. While the Organization of Petroleum Exporting Countries successfully managed crude oil prices despite petroleum product demand weakness due to worldwide economic slowdowns and political instability during 2002 and 2003, increased market demand and lower inventory levels were key factors during 2004. Product prices began to rise in 2002 and continued to exhibit an overall-strengthening trend in 2003 and 2004. The range of West Texas Intermediate (WTI) crude prices for 2004 was a low of $32.48 and a high of $55.17. The NYMEX settlement price for WTI, the U.S. benchmark crude oil, averaged $41.47 for 2004 compared to $30.99 for 2003 and $26.15 for 2002. The average posted price for the Company's 13 degree API heavy crude oil was $32.84 for 2004 compared to $25.27 for 2003 and $20.67 for 2002. The average posted price for the Company's Utah light crude oil was $39.62 for 2004 compared to $29.14 for 2003. The Company expects that crude prices will continue to be volatile in 2005.

While crude oil price differentials between WTI and California's heavy crude were fairly consistent in both 2002 and 2003 at just under $6.00 per barrel, the differential widened dramatically during 2004. The crude price differential between WTI and California's heavy crude oil averaged $8.57, $5.73 and $5.48 per barrel for 2004, 2003 and 2002, respectively. On December 31, 2004 the differential ended the year at $14.19. This differential has averaged over $14.00 per barrel in the first two months of 2005, and the Company is concerned that this differential may remain high for an extended period of time. Subsequent to the termination of the Company's current crude oil sales contract on December 31, 2004, a widening differential between WTI and California crude oil could adversely affect the Company's revenues, profitability and cash flows from its heavy oil operations. The Company will enter into a new contract if favorable terms can be achieved or may sell its crude oil into the spot market.

A price-sensitive royalty burdens one of the Company's California properties which produces approximately 4,000 barrels per day. This royalty is 75% of the amount of the heavy oil posted price above a base price which was $14.88 in 2004. This base price escalates at 2% annually, thus the threshold price is $15.18 per barrel in 2005.

Berry markets its crude oil production to competing buyers including independent marketers but primarily to major oil refining companies. Because of the Company's ability to deliver significant volumes of crude oil over a multi-year period, the Company was able to secure a thirty-nine month sales agreement, beginning in late 2002, with a major oil company whereby the Company sells over 90% of its California production under a negotiated pricing mechanism. This contract expires on December 31, 2005. Pricing in this agreement is 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. Both methods are calculated using a monthly determination. In addition to providing a premium above field postings, the agreement effectively eliminates the Company's exposure to the risk of widening WTI to California heavy crude price differentials and allows the Company to effectively hedge its production based on WTI pricing. This contract allowed the Company to improve its revenues over the posted price by approximately $13 million in 2004. The Brundage

Canyon crude oil, which is approximately 40 degree API gravity, is also linked to WTI and is priced at WTI less a fixed differential approximating $2.00 per barrel. This contract expires on September 30, 2006.

Berry markets produced natural gas from Utah, Wyoming and California. In October 2003, the Company began marketing produced gas from the Brundage Canyon field. Some of the natural gas from Brundage Canyon is sold in the Salt Lake City market at a Questar monthly index related price with an adjustment for transportation. Brundage Canyon volume in excess of Berry's firm pipeline transportation volume is sold at the field at a Questar daily spot related price. The Company owns a non-operated working interest in the South Joe Creek field in the Powder River Basin in Wyoming. Berry began marketing its working interest share of production in-kind from South Joe Creek in December 2002, at Glenrock, Wyoming at monthly

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Colorado Interstate Gas (CIG) index related prices. Additionally, produced gas from the Niobrara field in Colorado is also sold at monthly CIG index related price

For 2004, the first-of-month indices approximated $5.60 per MMBtu for SoCal Border, $5.15 per MMBtu for Rockies CIG and $5.05 for Rockies Questar. The closing price for the NYMEX prompt month natural gas contract averaged $6.18, $5.84 and $3.37 for years 2004, 2003 and 2002, respectively.

The Company has physical access to interstate gas pipelines, such as the Kern River Pipeline and the Questar Pipeline, as well as California intrastate systems owned by Southern California Gas Company and Pacific Gas & Electric (PG&E), to move gas to or from market. To avoid negative financial impacts to the Company should California pipeline capacity become constrained, the Company entered into a long-term gas transportation contract with Kern River Gas Transmission Company for 12,000 MMBtu/D. This is a ten year contract which began in May 2003. There is a proceeding currently before the Federal Energy Regulatory Commission (FERC) that may result in an upward adjustment in the transportation charge under this contract. The Company does not believe any such adjustment would have a material adverse impact on its operations. The Company also holds two firm transportation contracts on the Questar Pipeline system in Utah totaling 5,300 MMBtu/D.

From time to time, the Company enters into crude oil and natural gas hedge contracts, the terms of which depend on various factors, including Management's view of future crude oil and natural gas prices and the Company's future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil price downturn and protect certain operating margins in the Company's California operations. Currently, the hedges are in the form of swaps, however, the Company may use a variety of hedge instruments in the future. The Company's hedging activities resulted in a net reduction in revenue per BOE to the Company of $3.31 in 2004, $1.96 in 2003 and $.72 in 2002.

The following table summarizes the hedge position of the Company as of March 1, 2005:

Term	Average Barrels Per Day	Average Swap Price	Term	Average MMBtu Per Day	Average Swap Price
Crude Oil Sales			**Natural Gas Sales (CIG)**		
(NYMEX WTI)					
			Full Year 2005	1,000	$ 6.21
1st Quarter 2005	8,000	$ 41.38			
			Natural Gas Purchases		
2nd Quarter 2005	8,000	$ 40.58	**(SoCal Border)**		
3rd Quarter 2005	7,500	$ 40.84	1st Quarter 2005	9,000	$ 5.60
4th Quarter 2005	7,500	$ 40.67	2nd Quarter 2005	8,000	$ 5.19
1st Quarter 2006 (1)	1,250	$ 45.32	3rd Quarter 2005	6,667	$ 5.09
2nd Quarter 2006 (1)	1,250	$ 44.49	4th Quarter 2005	6,000	$ 5.05
3rd Quarter 2006 (1)	1,250	$ 43.78	1st Quarter 2006	5,000	$ 4.85

(1) These contracts were entered into subsequent to December 31, 2004.

Payments to the Company's counterparties are triggered when the monthly average prices are above the swap price in the case of the Company's crude oil and natural gas sales hedges and below the swap price for the Company's natural gas purchase hedge positions. Conversely, payments from our counterparties are received when the monthly average prices are below the swap price for the Company's crude oil and natural gas sales hedges and above the swap price for the Company's natural gas purchase hedge positions. Management regularly monitors the crude oil and natural gas markets and the Company’s financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging or other price protection is appropriate.

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Steaming Operations

Cogeneration Steam Supply

As of December 31, 2004, approximately 82% of the Company's proved reserves, or 90 million barrels, consisted of heavy crude oil produced from depths shallower than 2,000 feet. The Company, in pursuing its goal of being a cost-efficient heavy oil producer, 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 South Midway-Sunset field. The Company also owns a 42 MW cogeneration facility located in the Placerita field. Steam generation from these facilities, with a total steam capacity of approximately 38,000 barrels of steam per day (BSPD), is more efficient than conventional steam generation as both steam and electricity are concurrently produced from a common fuel stream. The Company also purchases approximately 2,000 BSPD under contract on favorable terms from a non-Company owned cogeneration facility.

Conventional Steam Generation

In addition to these cogeneration plants, the Company owns sixteen conventional boilers. The quantity of boilers operated at any point in time is dependent on the steam volume required for the Company to achieve its targeted production and on the price of natural gas compared to the price of crude oil sold. The total rated capacity of the conventional boilers is approximately 43,000 BSPD.

The cost of natural gas purchased (excluding transportation) per MMBtu averaged $5.46, $4.88 and $3.13 for 2004, 2003 and 2002, respectively. Most of the Company’s conventional steam generators were run in 2004 to achieve the Company’s goal of increasing heavy oil production to record levels.

The Company believes that it may become necessary to add additional steam capacity for its future development projects at Midway-Sunset, Placerita 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.

Operational Control

Ownership of these varied steam generation facilities and sources allows for maximum control over the steam supply, location, and to some extent the aggregated cost. The Company’s steam supply and flexibility are crucial for the maximization of oil production, cost control and ultimate reserve recovery.

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. The three facilities can also supply approximately 38,000 BSPD. 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 have 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 that they are advantageous versus conventional steam boilers. In 2004, the Company revised its allocation of cogeneration costs to oil and gas operations. 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.

Electricity Sales Contracts

Historically, the Company has sold electricity produced by its cogeneration facilities to two California public utilities, Southern California Edison Company (Edison) and Pacific Gas and Electric (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. The capacity payments are either fixed throughout the term of the agreement or can be adjusted from time to time by the California Public Utilities Commission (CPUC). The SRAC energy price is determined by a formula that reflects the utility's marginal fuel cost and a conversion efficiency that represents a hypothetical utility resource to generate electricity in the absence of the cogenerator. Natural gas is now 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

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cogeneration facilities. A proceeding is now underway at the CPUC to review and revise the methodology used to determine SRAC energy prices. This proceeding is currently scheduled to be completed by the end of 2005. 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.

The original SO contract for Placerita Unit 1 continues in effect through March 2009. The modified SRAC pricing terms reflect a fixed energy price of 5.37 cents/kilowatt per hour (KWh) until June 2006, at which time the energy price reverts to the SRAC pricing methodology. In 2002, the CPUC ordered the California utilities to offer SO contracts to certain cogeneration facilities with expired SO contracts, known as Qualifying Facilities or QFs, for a maximum term of one year. The Company met these requirements and entered into new SO contracts with Edison for its Placerita Unit 2 and with PG&E for its Cogen 38 and Cogen 18 facilities effective January 2003. These three new SO contracts resulted in improved electrical pricing in 2003 over 2002. All three SO contracts terminated on December 31, 2003, as originally ordered by the CPUC.

On December 18, 2003, the CPUC ordered the California utilities to continue to offer SO contracts to certain QFs with expired SO contracts, such as the Company, for a one year term beginning January 1, 2004. In the same decision, the CPUC also directed its staff to initiate a comprehensive review and revision of the SRAC pricing methodology. Edison appealed the legality of the December 18, 2003 CPUC decision that ordered the additional one-year extension of SO contracts, at the CPUC, but was unsuccessful. The Company executed a one year extension of its SO contract with Edison, effective January 1, 2004 for the Placerita Unit 2 facility, and executed similar one year extensions of its SO contracts with PG&E for its Cogen 38 and Cogen 18 facilities. Those one year extensions terminated as scheduled on December 31, 2004.

On January 22, 2004, the CPUC issued a decision that establishes the rules under which the California utilities will produce or procure energy for their customers for the next 5 to 10 years. Among other things, this decision ordered the California utilities to offer SO contracts to certain QFs whose SO contracts will terminate prior to December 31, 2005, such as the Company, for a term of 5 years. The SRAC price paid under these SO contracts is subject to the same prospective adjustments that were required in the prior CPUC decision that ordered the one-year extension. 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. Edison and PG&E have challenged, in the California Court of Appeal, the legality of the CPUC decision that ordered the utilities to enter into the one-year SO contracts for 2004, and the decision that ordered the utilities to enter into five-year SO contracts. Arguments in this case were heard by the court in March 2005. The Company believes that QFs, 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.

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	Mar-09	20	-	6,600
Placerita Unit 2	SO1	Edison	Dec-09	16	4	6,700

South Midway-Sunset						
Cogen 18	SO1	PG&E	Dec-09	12	4	6,600
Cogen 38	SO1	PG&E	Dec-09	37	-	18,000

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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 compliance with environmental, health and safety laws and other regulations are inextricably connected to normal operating expenses such that the Company is unable to separate the expenses related to these matters.

Currently, California environmental laws and regulations are being revised to lower emissions from stationary sources. Although these requirements do have a substantial impact upon the energy industry, generally these requirements do not appear to affect the Company any differently, or to any greater or lesser extent, than other companies in California. Berry believes that compliance with environmental laws and regulations will not have a material adverse effect on the Company's operations or financial condition. There can be no assurances, however, that changes in, or additions to, laws and regulations regarding the protection of the environment will not have such 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. The Company is not aware of any environmental claims existing as of December 31, 2004 that would have a material impact upon the Company's financial position, results of operations, or liquidity.

Regulation of Oil and Gas

The oil and gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases the Company's cost of doing business and, consequently, may affect profitability, these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The Company's operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribes, in which the Company operates also regulate one or more of the following:

- 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.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These 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.

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Moreover, each state generally imposes a property, production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

A portion of the Company's leases in the Uinta Basin are, and some of the Company's future leases in this and other areas may be, regulated by Native American tribes. In addition to regulation by various federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations. Various federal agencies within the U.S. Department of the Interior, particularly the Minerals Management Service and the Bureau of Indian Affairs, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs. However, each Native American tribe is a sovereign nation and has the right to enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members, and numerous other conditions that apply to lessees, operators, and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, the Company is 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. One or more of these requirements may increase the Company's cost of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

Federal Energy Regulation

The enactment of the Public Utility Regulatory Policies Act of 1978, as amended (PURPA), and the adoption of regulations thereunder by the FERC provided incentives for the development of cogeneration facilities such as those owned by the Company. A domestic electricity generating project must be a Qualifying Facility (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. 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. Also, a QF must not be controlled or more than 50% owned by one or more electric utilities or by most electric utility holding companies, or one or more subsidiaries of such a utility or holding company or any combination thereof. 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 of critical importance to the Company.

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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. 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 low cost structure, transaction flexibility, strong financial position, experience and determination.

Employees

On December 31, 2004, the Company had 157 full-time employees, up from 129 full-time employees on December 31, 2003. As of March 1, 2005, and following the acquisition of the Niobrara gas producing assets in Colorado, the Company has 181 employees. On-site production operation services, such as pumping, maintenance, inspection and testing, are generally provided by independent contractors.

Oil and Gas Properties

Unless otherwise noted, gross acreage, net wells, fourth quarter production, and 2004 year-end reserves are used in the property descriptions below.

San Joaquin Valley Basin

Midway-Sunset, California - Berry owns and operates working interests in 38 properties consisting of 4,528 acres located in the Midway-Sunset field. The Company estimates these properties account for approximately 63% of the Company's proved oil and gas reserves and approximately 57% of its current daily production. Of these properties, 23 are owned in fee and the Company's average working interest in this field is approximately 95%. The wells produce from an average depth of approximately 1,200 feet, and rely on thermal EOR methods, primarily cyclic steaming.

During 2004, 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. Additionally, a steam flood pilot was initiated in the diatomite formation. In 2005, the Company plans to drill an additional 54 wells, including 8 horizontal wells and 26 wells in the diatomite formation.

Poso Creek, California - The McVan property, consisting of 560 acres in the Poso Creek field, was purchased in March 2003. An additional 120 acres were acquired in 2004 offsetting the Company's existing position to the southeast. Year-end 2004 proved reserves comprise 2% of Berry’s proved oil and gas reserves while year-end production has increased to over 400 barrels per day.

During 2004, one service well was drilled and a ten well workover program was completed. Steam injection was also reinitiated at the McVan property in 2004. Plans for 2005 include the drilling of four new development wells, further well workovers and the return to production of a number of idle wells.

Los Angeles Basin

Placerita, California - The Company’s assets in the Placerita field consist of nine leases and four fee properties totaling approximately 965 acres. The average depth of these wells is 1,800 feet and the properties rely on thermal recovery methods, primarily steam flooding. The property accounts for approximately 16% of proved reserves and

13% of current daily production.

During 2004, three new wells were drilled to begin redevelopment on the Castruccio property which the Company acquired several years ago. In 2005, the Company plans to drill 12 wells in the north end of the field to continue a major expansion of the existing steam flood.

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Ventura Basin

Montalvo, California - Berry owns a 100% working interest in six leases totaling 8,563 acres in the Ventura Basin comprising the entire Montalvo field. The State of California is the lessor for two of the six leases. The Company estimates current proved reserves from Montalvo account for approximately 6% of Berry's proved oil and gas reserves and approximately 4% of Berry's current daily production. The wells produce from an average depth of approximately 11,500 feet. No new wells were drilled in 2004; however one well was remediated and returned to production. During 2005, one idle well is scheduled to be returned to production.

Uinta Basin

Brundage Canyon, Utah - The Brundage Canyon leasehold in Duchesne County, Utah consists of federal, tribal and private leases totaling 47,300 gross acres (45,420 net). The Company estimates that the Brundage Canyon properties account for approximately 12% of proved oil and gas reserves and approximately 23% of current daily production. There are 164 wells in the Brundage Canyon field producing oil and associated natural gas with an average well depth of 6,000 feet.

In 2004, the Company continued its focus on development of the Brundage Canyon property, drilling 54 wells including several 40-acre infill tests. The Company's objectives for 2005 include the drilling of 59 additional wells, including nine 40-acre infill wells and the recompletion of 20 existing wells.

In September 2004, the Company entered into a farm-out agreement pursuant to which Bill Barrett Corporation had the right to earn a 75% working interest in the deep Mesaverde formation and deeper horizons within the Brundage Canyon Field by drilling a deep exploratory test. The Company's partner commenced the drilling of its initial deep exploratory well in Brundage Canyon in November 2004 and abandoned it in January 2005, pending the further evaluation of a 3-D seismic survey and assessment of the optimal completion technology.

Lake Canyon Prospect, Utah - In 2004, the Company and Bill Barrett Corporation entered into a joint exploration and development agreement with the Ute Indian Tribe to explore and develop approximately 124,500 gross (62,250 net) prospective acres of tribal lands in the Uinta Basin in Utah. The Company also purchased an interest in approximately 44,500 gross (22,250 net) acres of privately owned lands near the tribal acreage. The 169,000 gross acre block 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 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 Company plans to drill two shallow test wells in the Green River trend and participate in one deep test well in the Mesaverde formation in 2005.

Coyote Flats Prospect, Utah - In December 2004, the Company entered into a development agreement with Petro-Canada Resources (USA) Inc. to develop their Coyote Flats prospect in the Uinta Basin. The property is located approximately 45 miles southwest of the Company's Brundage Canyon property. The Company is obligated to drill three test wells into the Ferron sand to a depth of approximately 7,500 feet and also drill a six well Emery coalbed methane pilot, found at approximately 4,500 feet. Upon the completion of this total nine well drilling program, the Company will earn an interest in the approximately 69,250 gross (33,500 net) acres. The Company has drilled one Ferron sand test well in early 2005 which was deemed to be a dry hole. The Company plans to drill the remaining two Ferron sand test wells and the Emery coalbed methane pilot wells during 2005. Future development plans will be determined jointly by the Company and its 50% partner, Petro-Canada Resources.

Denver-Julesburg Basin

Niobrara Field, Colorado - In January 2005, the Company acquired certain interests in the Niobrara field in northeastern Colorado for approximately $105 million. The properties consist of approximately 127,000 gross (69,500 net) acres and the Company has a 52% working interest. Current production is approximately 9 MMcf of natural gas per day. The acquisition also includes approximately 200 miles of a pipeline gathering system and gas compression facilities for delivery into interstate gas lines. In 2005, the Company plans to drill approximately 60 gross wells as part of its ongoing development program and the initiation of the 40-acre infill program from the existing 80-acre development.

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Tri-State Prospect, Colorado, Nebraska and Kansas - In January 2005, the Company acquired a working interest in approximately 390,000 gross (172,250 net) prospective acres, located in eastern Colorado, western Kansas and southwestern Nebraska, from Bill Barrett Corporation. The 50% joint venture will apply seismic technologies to explore and, if successful, develop the Niobrara formation for biogenic 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 to 4,800 feet. The Company believes the potential of the Tri-State area can be exploited by using new drilling techniques, with 3-D seismic technology to assess structural complexity, and estimate potentially recoverable oil and gas and determine drilling locations. The Company plans to drill 8 gross wells (4 net) in 2005.

Other

South Joe Creek, Wyoming - The Company holds a 15.83% non-operated working interest in the South Joe Creek coalbed methane field which represents interests in federal, state and private leases totaling 5,106 acres in the northeastern portion of the Powder River Basin in Wyoming. The property has 96 wells (14 net). The property accounts for 1% of production while reserves are minimal. There are no plans at this time to drill any new wells in 2005.

Mickelson Creek, Wyoming - In 2003, the Company purchased three federal leases located in the Mickelson Creek field in Sublette County, Wyoming. There are currently five wells on the 2,800 acre property. Reserves and production from these properties are minimal. The Company plans to drill two wells on this property in 2005.

Kansas and Illinois Coalbed Methane (CBM) Projects - The Company holds 163,000 and 55,000 net acres in Eastern Kansas and Central Illinois, respectively, as prospective acreage for coalbed methane production. The Company drilled a pilot in each state in late 2002, and in 2003 the Company determined both these pilots were non-commercial. As such, the Company has no reserves or production in either state as of December 31, 2004. The Company continues to assess the potential of these properties.

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The following is a summary of the Company's capital expenditures incurred during 2004 and 2003 and budgeted capital expenditures for 2005.

CAPITAL EXPENDITURES SUMMARY
(in thousands)

	2005 (Budgeted) (1)	2004	2003
CALIFORNIA			
Midway-Sunset Field			
New wells	$ 11,012	$ 11,376	$ 10,710
Remedials/workovers	420	1,415	1,718
Facilities - oil & gas	6,850	4,045	3,136
Facilities - cogeneration	3,435	1,055	231
General	2,001	2,144	187
	23,718	20,035	15,982
Other California Fields			
New wells	5,295	426	6,509
Remedials/workovers	4,463	1,589	1,084
Facilities - oil & gas	2,470	3,416	1,676
Facilities - cogeneration	250	555	370
	12,478	5,986	9,639
Total California	36,196	26,021	25,621
ROCKIES AND MID-CONTINENT			
Uinta Basin			
New wells	47,914	39,467	14,298
Remedials/workovers	2,050	4,597	234
Facilities	4,332	1,979	146
	54,296	46,043	14,678
DJ Basin			
New wells/workovers	5,660	-	-
Land and seismic	3,573	-	-
	9,233	-	-
Other	3,593	161	1,256
Total Rocky Mountain and Mid-Continent	67,122	46,204	15,934
Other	3,682	-	-
Totals	$ 107,000	$ 72,225	$ 41,555

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

Operations.

In recent years, the Company has concentrated on growth through development of existing assets and strategic acquisitions. The Company's acquisition and development strategy will include exploratory drilling in the future.

Enhanced Oil Recovery Tax Credits

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, the Company is able to achieve credits approximating 12% of its 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 the Company's tax liability down to, but not below, its alternative minimum tax liability. This credit is significant in reducing the Company's income tax liabilities and effective tax rate.

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Oil and Gas Reserves

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, 2004. 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, 2004. For the Company's operated properties, such reserve estimates are filed annually with the U.S. Department of Energy. See the Supplemental Information About Oil & Gas Producing Activities (Unaudited) for the Company's oil and gas reserve disclosures.

Production

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

	2004	2003	2002
Net annual production:(1)			
Oil (Mbbls)	7,044	5,827	5,123
Gas (Mmcf)	2,839	1,277	769
Total equivalent barrels(2)	7,517	6,040	5,251
Average sales price:			
Oil (per Bbl) before hedging	$ 33.43	$ 24.41	$ 20.27
Oil (per Bbl) after hedging	29.89	22.37	19.54
Gas (per mcf) before hedging	6.13	4.40	2.22
Gas (per mcf) after hedging	6.12	4.43	2.22
Per BOE before hedging	33.64	24.48	20.11
Per BOE after hedging	30.32	22.52	19.39
Average operating cost – oil and gas production (per BOE)	10.96	10.37	8.61

Mbbls - Thousands of Barrels
Mmcf - Million Cubic Feet
BOE - 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, 2004, the Company's properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	8,167	8,167	7,038	7,038	15,205	15,205
Utah (1)	9,520	9,360	82,363	58,352	91,883	67,712

Wyoming	3,800	750	4,266	2,250	8,066	3,000
Illinois	-	-	58,318	54,601	58,318	54,601
Kansas	-	-	168,960	163,046	168,960	163,046
Other	80	19	-	-	80	19
	21,567	18,296	320,945	285,287	342,512	303,583

(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.

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

As of December 31, 2004, the Company has 1,947 gross oil wells (1,909 net) and 103 gross gas wells (20 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. Costs of $.5 million which were incurred as of December 31, 2004 were charged to expense and are reflected on the Company's income statement under "Dry-hole, abandonment and impairment."

Drilling Activity

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

	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled:						
Productive	5	5	-	-	-	-
Dry(1)	-	-	-	-	11	11
Development wells drilled: (2)						
Productive	123	111	121	119	81	76
Dry(1)	-	-	1	1	-	-
Total wells drilled:						
Productive	128	116	121	119	81	76
Dry(1)	-	-	1	1	11	11

(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. The 11 wells drilled in 2002 were determined to be dry holes in 2003.*

(2) *Wells drilled include 12 wells gross, 2 wells net for 2004, 2 wells gross, .3 wells net for 2003 and 6 wells gross, 1 well net for 2002 at South Joe Creek where the Company holds a 15.83% working interest.*

As of December 31, 2004, two development wells were being drilled on the Brundage Canyon property, one exploratory well was being drilled on the Coyote Flats prospect and one exploratory well was being drilled on the Company's Midway-Sunset property. The well being drilled on the Midway-Sunset property and the well being drilled on the Coyote Flats prospect were determined to be non-commercial in February 2005. Costs of $.5 million which were incurred as of December 31, 2004 were charged to expense and are reflected on the Company's income statement under "Dry-hole, abandonment and impairment."

Title and Insurance

To the best of the Company's knowledge, there are no defects in the title to any of its principal properties including related facilities. Notwithstanding the absence of a recent title opinion or title insurance policy on all of its properties, the Company believes it has satisfactory title to its properties, subject to such exceptions as the Company believes are customary and usual in the oil and gas industry and which the Company believes will not materially impair its ability to recover the proved oil and gas reserves or to obtain the resulting economic benefits.

As is customary in the industry in the case of undeveloped properties, often little investigation of record title is made at the time of acquisition. Investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. However there can be no assurance that all matters will be discovered during such investigation and this is a risk assumed by the Company. Individual properties may be subject to burdens that the Company believes do not materially interfere with the use, or affect the value, of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; and
- burdens such as net profits interests.

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The oil and gas business can be hazardous, involving unforeseen circumstances such as blowouts or environmental damage. Although it is not insured against all risks, the Company maintains a comprehensive insurance program to address the hazards inherent in operating its oil and gas business.

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

None.

Executive Officers of the Registrant

Listed below are the names, ages (as of December 31, 2004) 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, 51, 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, 48, 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, 38, has been Senior Vice President of Corporate Development since June 2004 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.

LOGAN MAGRUDER, 48, has been Senior Vice President of the Rocky Mountain and Mid-Continent Region since June 2004 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.

GEORGE T. CRAWFORD, 44, has been Vice President of Production since December 2000 and was Manager of Production, from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, was previously the Production Engineering Supervisor for ARCO Western Energy, a subsidiary of Atlantic Richfield Corp. (ARCO). Mr. Crawford was employed by ARCO from 1989 to 1998 in numerous engineering and operational assignments including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

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BRIAN L. REHKOPF, 57, has been Vice President of Engineering since March 2000 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 Western Energy since 1992 and an Operations Engineering Supervisor with ARCO from 1988 to 1992. Mr. Rehkopf is also an Assistant Secretary for the Company.

SHAWN M. CANADAY, 29, 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, 58, has been Controller since December 1985.

KENNETH A. OLSON, 49, 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 and 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 of Notes to the Financial Statements.

Berry's Class A Common Stock is listed on the New York Stock Exchange under the symbol (NYSE:BRY). The Class B Stock is not publicly traded. The market data and dividends for 2004 and 2003 are shown below:

	2004			2003		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 27.30	$ 18.25	$ 0.11	$ 17.01	$ 14.65	$ 0.10
Second Quarter	31.07	25.09	0.11	18.38	14.40	0.15
Third Quarter	38.44	27.73	0.18	19.17	16.96	0.11
Fourth Quarter	50.58	35.16	0.12	20.95	17.90	0.11

The closing price per share of Berry's Common Stock, as reported on the New York Stock Exchange Composite Transaction Reporting System for March 14, 2005, December 31, 2004 and December 31, 2003 was $55.17, $47.70, and $20.25, respectively.

The number of holders of record of the Company's Common Stock was 643 as of March 14, 2005. There was one Class B Shareholder of record as of March 14, 2005.

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. The Company's annual dividend is currently $.48 per share, paid quarterly in March, June, September and December.

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Since Berry Petroleum Company's formation in 1985 through December 31, 2004, the Company has paid dividends on its Common Stock for 61 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. Annual dividend payments are limited by covenants in the Company's credit facility to the greater of $13 million or 75% of net income. The total dividends paid by the Company in 2004 and 2003 were $11.4 million and $10.2 million, respectively, which is in compliance with these covenants.

As of December 31, 2004, dividends declared on 4,000,894 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 (1)(3) (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance (2)(3) (c)
Equity compensation plans approved by security holders	1,565,625	$25.41	-
Equity compensation plans not approved by security holders	-	-	-
Total	1,565,625	$25.41	-

(1) Does not include 56,204 shares earned and reserved for issuance from the Non-Employee Directors Deferred Compensation Plan for past compensation deferred.

(2) Does not include 192,999 shares available and reserved for future issuance from the Non-Employee Directors Deferred Compensation Plan in lieu of future option issuance from the Company's 1994 Non-Statutory Stock Option Plan which expired on December 2, 2004.

(3) Based on historical averages, the actual shares issued from the 1994 Non-Statutory Stock Option Plan have been at a ratio of approximately four options exercised for each share of Common Stock issued.

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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, 2004 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data).

	2004	2003 (1)	2002 (1)	2001 (1)	2000 (1)
Audited Financial Information					
Statement of Income Data:					
Sales of oil and gas	$ 226,876	$ 135,848	$ 102,026	$ 100,146	$ 118,801
Sales of electricity	47,644	44,200	27,691	35,133	51,420
Operating costs – oil and gas production	82,419	62,554	45,217	38,114	48,594
Operating costs – electricity generation	46,191	42,351	26,747	36,890	45,464
General and administrative expenses (G&A)	20,354	12,868	9,215	8,718	6,782
Depreciation, depletion & amortization (DD&A) - oil and gas production	29,752	17,258	13,388	13,225	11,374
DD&A - electricity generation	3,490	3,256	3,064	3,295	2,656
Net income	69,187	32,363	29,210	20,985	37,766
Basic net income per share	3.16	1.49	1.34	0.96	1.71
Diluted net income per share	3.08	1.47	1.33	0.95	1.71
Weighted average number of shares outstanding (basic)	21,894	21,772	21,741	21,973	22,029
Weighted average number of shares outstanding (diluted)	22,470	22,031	21,902	22,162	22,145
Balance Sheet Data:					
Working capital	$ (3,840)	$ (3,540)	$ (2,892)	$ 6,314	$ (963)
Total assets	412,104	340,377	259,325	238,779	238,572
Long-term debt	28,000	50,000	15,000	25,000	25,000
Shareholders' equity	263,086	197,338	172,774	153,590	145,220
Cash dividends per share	0.52	0.47	0.40	0.40	0.40
Operating Data:					
Cash flow from operations	124,613	64,825	57,895	35,433	65,934
Capital expenditures (excluding acquisitions)	72,225	41,555	30,632	14,895	25,253
Property/facility acquisitions	2,845	48,579	5,880	2,273	3,182
Unaudited Operating Data					
Oil and gas producing operations (per BOE):					
Average sales price before hedging	$ 33.64	$ 24.48	$ 20.11	$ 19.63	$ 23.01
Average sales price after hedging	30.32	22.52	19.39	19.79	21.72
Average operating costs - oil and gas production	10.96	10.37	8.61	7.64	9.29
G&A	2.71	2.13	1.75	1.73	1.24

DD&A - oil and gas production	3.96	2.86	2.55	3.28	2.57
Production (MBOE)	7,517	6,040	5,251	5,044	5,467
Production (MWh)	776	767	748	483	764
Proved Reserves Information:					
Total BOE	109,836	109,920	101,719	102,855	107,361
Standardized measure (2)	$ 686,748	$ 528,220	$ 449,857	$ 278,453	$ 501,694
Present value (PV10) of estimated future net cash flow before income taxes	876,502	683,124	599,826	358,653	719,882
Year-end average BOE price for PV10 purposes	29.87	25.89	24.91	14.13	21.13
Other:					
Return on average shareholders' equity	31.06%	17.50%	17.90%	14.00%	28.80%
Return on average total assets	18.60%	10.80%	11.70%	8.80%	16.90%

(1) Information has been revised to reflect the Company's change in allocation of cogeneration costs to oil and gas operations. See Note 2 to the Company's financial statements.

(2) See Supplemental Information About Oil & Gas Producing Activities.

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

Overview

The Company is an independent oil and natural gas exploration and production company operating in California and the Rocky Mountain and Mid-Continent regions. The Company's objective is to increase shareholder value by profitably growing reserves and production, primarily through drilling operations and strategic acquisitions. The Company seeks high quality development, exploitation and exploration projects with potential for providing long-term drilling inventories that generate high returns. Approximately three-quarters of the Company'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 90% of these volumes are from oil production, and the majority of those volumes are from heavy oil production in California. The other quarter of the Company's revenues are derived from electricity sales from cogeneration facilities which supply over half of the Company’s steam requirement for use in its California thermal heavy oil operations. The Company has invested in these facilities for the purpose of lowering its steam costs which are significant in the production of heavy crude oil.

The Company's revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on its ability to find, develop and acquire oil and gas reserves that are economically recoverable. The preparation of financial statements in conformity with generally accepted accounting principles requires estimates and assumptions that affect its reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. The Company uses the successful efforts method of accounting for its oil and gas operations.

Oil and Gas Prices. Prices for oil and gas fluctuate widely. Oil and gas prices affect:

- the profitability of the Company;
- the amount of cash flow available for capital expenditures;
- the Company's ability to borrow and raise additional capital; and
- the amount of oil and gas that the Company can economically produce.

Approximately 83% of the Company's current production is California heavy crude oil which sells at a discount to WTI crude pricing. The risk of widening price differentials between WTI and the Company's California heavy crude oil is mitigated by a crude oil sales contract under which the Company sells over 90% of its California production. Pricing in the existing agreement is based upon the higher of the average of the local field posted prices plus a fixed premium, or WTI minus a fixed differential approximating $6.00 per barrel. This contract expires on December 31, 2005. While crude oil price differentials between WTI and California’s heavy crude were fairly consistent in both 2002 and 2003 at just under $6.00 per barrel, the differential widened dramatically during 2004, with the average climbing to $8.57. On December 30, 2004 the differential ended the year at $14.19. This differential has averaged over $14.00 per barrel in the first two months of 2005, and the Company is monitoring this differential and trying to determine the reasons behind the breakout from the historical norm. Subsequent to the termination of the current contract, a widening differential between WTI and California crude oil could adversely affect the Company's revenues, profitability and cash flows from its heavy oil operations. The Company will enter into a new contract if favorable terms can be achieved or may sell its crude oil into the spot market.

The Company's cogeneration plants and conventional steam boilers require significant volumes of natural gas for use as fuel in generating steam used in the production of its heavy oil. A substantial increase in California natural gas prices without a corresponding increase in heavy crude oil prices would adversely affect the Company's California heavy oil operations. This risk is partially offset by the Company's cogeneration plants, as their revenue is currently linked to the price of California natural gas available for purchase at California's border. A change in these electricity contracts to a formula that is not closely linked to the price of California natural gas would increase the Company's risk related to an increase in California natural gas prices. At times, California natural gas prices have been more volatile than other markets in the United States. To mitigate the risk of volatile California natural gas prices, the Company has a firm transportation contract with Kern River Gas Transmission Company for 12,000 MMBtu/D, approximately one-third of the Company's current natural gas demand, until April 2013. There is a proceeding currently before the Federal Energy Regulatory Commission (FERC) that may result in an upward adjustment in the transportation charge under this contract. The Company does not believe any such adjustment would have a material adverse impact on its operations.

The Company generally hedges a substantial, but varying, portion of its anticipated future oil production and natural gas used as fuel in its enhanced oil recovery operations. The Company uses hedging to, among other things, reduce its exposure to commodity price fluctuations.

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Reserve Replacement. Generally, the Company's producing properties in California have a modest initial production rate with a gradual production decline and long reserve life. The Company's Rocky Mountain assets have high initial production rates, followed by steeper declines and a shorter reserve life. The Company's Niobrara natural gas assets have modest initial production rates, a gradual decline and long reserve life. The Company attempts to locate and develop or acquire new oil and gas reserves to grow the Company and replace those reserves being depleted by production. Substantial capital expenditures are required to find, develop and acquire oil and gas reserves.

Significant Estimates. The Company believes the most difficult, subjective or complex judgments and estimates it must make in connection with the preparation of its financial statements are:

- determining its proved oil and gas reserves;
- timing of its future drilling, development and abandonment activities;
- future costs to develop and abandon oil and gas properties;
- estimates and timing of certain tax items, deductions and credits,
- estimates related to certain, if any, environmental impacts of operations, and
- the valuation of derivative positions.

Please see “Other Factors Affecting the Company's Business and Financial Results” in this Item 7 for a more detailed discussion of a number of other factors that affect the Company's business, financial condition and results of operations.

The following discussion provides information on the results of operations for each of the three years ended December 31, 2004, 2003 and 2002 and the financial condition, liquidity and capital resources as of December 31, 2004 and 2003. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

The profitability of the Company's operations in any particular accounting period will be directly related to the average realized prices of oil, gas and electricity sold, the type and volume of oil and gas produced and electricity generated and the results of development, exploitation, acquisition and exploration activities. The average realized prices for natural gas and electricity will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by world supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. The cost of natural gas used in the Company's steaming operations and electrical generation, production rates, labor, maintenance expenses and production taxes are expected to be the principal influences on operating costs. Accordingly, the results of operations of the Company may fluctuate from period to period based on the foregoing principal factors, among others.

Results of Operations

In 2004, the Company achieved a record year for revenue and net income. The Company earned $69.2 million, or $3.08 per share (diluted), in 2004 on revenues of $275 million, up 114% from $32.4 million, or $1.47 per share (diluted), on revenues of $181 million in 2003, and up from $29.2 million, or $1.33 per share (diluted), on revenues of $131 million earned in 2002.

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The following table presents certain operating data for the years ended December 31:

		2004		2003		2002
Oil and Gas						
Oil Production (Bbl/D)		19,246		15,966		14,036
Natural Gas Production (Mcf/D)		7,752		3,499		2,106
Total (BOE/D)		20,537		16,549		14,387
Per BOE:						
Average sales price before hedging	$	33.64	$	24.48	$	20.11
Average sales price after hedging		30.32		22.52		19.39
Electricity						
Electric power produced - MWh/D		2,121		2,100		2,050
Electric power sold – MWh/D		1,915		1,925		1,848
Average sales price/MWh before hedging	$	70.24	$	62.91	$	40.06
Average sales price/MWh after hedging	$	70.24	$	61.95	$	39.64
Fuel gas cost/MMBtu (excluding transportation)	$	5.46	$	4.88	$	3.13

Revenues. The Company's revenues are derived from the sale of its oil and gas production and electricity generation. The Company's revenues may vary significantly from year to year as a result of changes in commodity prices and/or production volumes. Sales of oil and gas were $227 million in 2004, up 67% from $136 million in 2003 and up 123% from $102 million in 2002. This significant improvement was due to increases in both oil prices and production levels. The increase in oil prices contributed roughly two-thirds of the revenue increase and the increase in production volumes contributed the other third. The 2004 average sales price per BOE of the Company’s oil and gas, net of hedging, was $30.32, up 35% and 56% from $22.52 and $19.39 received in 2003 and 2002, respectively. Approximately 94% of the Company’s oil and gas sales volumes in 2004 were crude oil, with 80% of the crude oil being heavy oil produced in California which is sold under a contract based on the higher of WTI minus a fixed differential or the average posted price of three local posters plus a premium. This contract expires on December 31, 2005. With this contract in place, the Company has effectively eliminated the risk of a differential larger than approximately $6.00 per barrel between the Company's heavy crude oil and WTI prices through December 31, 2005. The average differential widened during 2004 to $8.57 and was over $14.00 for the first two months of 2005. In 2004, the Company estimates that its revenues benefited from this contract by approximately $13 million, and at a current differential of approximately $14.00 per barrel, the Company estimates that its revenues in 2005 will benefit from the contract by approximately $45 million. The Company is monitoring the differential and investigating the possible reasons as to why this differential has expanded over its historical average. While the Company believes that over time the differential will be more in line with its historical norm, it is unlikely that the Company will be able to obtain terms similar for crude oil sales in 2006 to the current contract. The Company is confident that it will be able to secure a contract for the sale of its California heavy crude oil if it so desires. The Brundage Canyon crude oil is priced at WTI less a fixed differential approximating $2.00 per barrel. During 2004, WTI prices per barrel reached a high of $55.17, a low of $32.48 and averaged $41.47 for the year compared to an average of $30.99 and $26.15 in 2003 and 2002, respectively. In 2004, the difference between WTI and the Company's average sales price, net of hedging, consists of product quality differentials of $5.02 per BOE, hedge payments of $3.32 per BOE, and price sensitive royalties of $2.81 per BOE. The Company anticipates crude oil prices to remain strong in 2005 and into 2006. However, since crude oil prices are impacted by world supply and demand, instability in the Middle East and other factors, actual prices may vary significantly from current prices.

As a result of hedging activities, the Company's revenue was reduced by $24.9 million, $11.8 million and $3.8 million in 2004, 2003 and 2002, respectively, which was reported as a reduction in "Sales of oil and gas" in the Company's financial statements. These price hedging activities resulted in a net reduction in revenue per BOE to the Company of $3.31 in 2004, $1.96 in 2003, and $.72 in 2002. The Company has hedged approximately 7,750 barrels per day of its oil production for 2005 at prices averaging near WTI $40.75 per barrel. The Company primarily is at risk to reductions in operating income as a result of declines in crude oil and electricity prices and increases in natural gas prices. The Company's exposure to increasing natural gas prices will be less in 2005 than 2004 due to the additional gas production from the Niobrara field and potential increases in natural gas production in the Uinta Basin. The Company's 2005 sales volume from natural gas is expected to approximately double from its 2004 sales volume. To assist in mitigating these risks, the Company periodically enters into various types of commodity hedges. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk”.

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Acquisitions. In August 2003, the Company completed the acquisition of its Brundage Canyon properties for approximately $45 million. The properties represented Berry’s first substantial acquisition of a Company-operated core asset outside of California, and was consistent with the Company’s goal of building a strong asset portfolio in the Rocky Mountain region. At acquisition, the properties produced less than 1,200 BOE/day of light crude oil and natural gas. In 2003 and 2004, the Company drilled 82 new wells and completed a number of workovers, increasing production to approximately 5,000 BOE/day at December 31, 2004. The Company believes the Rockies provide the Company with solid upside potential and is committed to increasing its acreage position in this region. In September 2004, the Company entered into a farm-out agreement pursuant to which Bill Barrett Corporation had the right to earn a 75% working interest in the deep Mesaverde formation and deeper horizons within the Brundage Canyon field by drilling a deep exploratory test. The Company's partner commenced the drilling of its initial deep exploratory well in Brundage Canyon in November 2004 and abandoned it in January 2005, pending further evaluation of a 3-D seismic survey and assessment of optimal completion technology. No costs were incurred by the Company related to the drilling or abandonment of this well.

As part of the Company's expansion into the Rockies, in July 2004, the Company and Bill Barrett Corporation completed a joint exploration and development agreement with the Ute Indian Tribe to explore for and develop potential hydrocarbons on 124,500 gross (62,250 net) prospective acres of tribal lands in the Uinta Basin in Utah. The Company also purchased an interest in 44,500 gross (22,250 net) acres of fee lands near and/or adjacent to the tribal acreage. The total 169,000 gross acre block is located immediately west of the Company’s Brundage Canyon producing properties. The total cost to the Company was approximately $2 million. The Company will drill and operate the shallow wells which target light oil 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 Company is committed to drill two shallow test wells in the Green River trend and participate in one deep test well in the Mesaverde formation in 2005. The Company's minimum obligation under its exploration and development agreement is $10.5 million. The Company plans to commence drilling in the summer of 2005.

In December 2004, the Company entered into a development agreement with Petro-Canada Resources (USA) Inc. to develop their Coyote Flats prospect in the Uinta Basin. The property is located approximately 45 miles southwest of the Company’s Brundage Canyon property. The Company is obligated to drill three test wells into the Ferron sand to a depth of approximately 7,500 feet and also drill a six-well Emery coalbed methane pilot, at approximately 4,500 feet. Upon the completion of this total nine well drilling program, the Company will earn an interest in the approximately 69,250 gross acres (33,500 net). The Company has drilled one Ferron sand test well in early 2005 which was deemed to be a dry hole. The Company plans to drill the remaining two Ferron sand test wells and the Emery coalbed methane pilot wells during 2005. The Company estimates that its total cost under this agreement will be approximately $10.3 million, which consists of $1.3 million paid at signing and approximately $9 million for the drilling of the obligation wells. Future development plans will be determined jointly by the Company and its 50% partner, Petro-Canada Resources.

In January 2005, the Company acquired certain interests in the Niobrara fields in northeastern Colorado for approximately $105 million. The properties consist of approximately 127,000 gross (69,500 net) acres. Current production is approximately 9 MMcf of natural gas per day, with estimated proved reserves of 87 Bcf. The acquisition also includes approximately 200 miles of a pipeline gathering system and gas compression facilities for delivery into interstate gas lines. In 2005, the Company plans to drill approximately 60 gross wells as part of the development of this asset.

In January 2005, the Company acquired a working interest in approximately 390,000 gross (172,250 net) prospective acres, located in eastern Colorado, western Kansas and southwestern Nebraska, from Bill Barrett Corporation. The

Company and its 50% partner will jointly explore and develop shallow Niobrara biogenic natural gas, Sharon Springs Shale gas and deeper Pennsylvanian formation oil assets on the acreage. The Company paid approximately $5 million for its working interest in the acreage. The Company believes the potential of the Tri-State area can be exploited by using new drilling techniques, with 3-D seismic technology to assess structural complexity, and estimate potentially recoverable oil and gas and determine drilling locations. The Company anticipates drilling eight gross wells with its partner in 2005 to test the Niobrara gas potential.

Royalty Conversion. In December 2004 certain royalty owners exercised their right to convert their royalty interest into a working interest on the Company's Formax property in the Midway-Sunset field. This resulted in a reduction to the Company of 1.8 million barrels of reserves and represents approximately 450 BOE/day at year end production levels. The Company has no other similar conversion rights by any other current royalty owners.

Oil and Gas Production. The Company’s oil and gas production reached record levels in 2004, averaging 20,537 BOE/day, up 24% from its 2003 level of 16,549 BOE/day, the previous record for the Company and up 30% from 14,387 BOE/day in 2002. This significant increase was due primarily to the success of the Company's continued development of its Brundage Canyon properties in Utah, acquired in August 2003. With the drilling of 26 new wells in 2003 and 54 additional wells in

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2004, these properties contributed 4,400 BOE/day for all of 2004. With the continued development of its California and Brundage Canyon properties and the initial development of it newly acquired assets in the Rocky Mountain and Mid-Continent region, the Company anticipates that oil and gas production will average in excess of 23,000 BOE/day in 2005 or an approximate 12% increase in production over 2004.

Electricity Generation. The Company produced 2,121 MWh/D of electricity in 2004, compared to 2,100 MWh/D in 2003 and 2,050 MWh/D produced in 2002. During 2004, the Company received an average sales price, before hedging, for its electricity per MWh of $70.24 compared to $62.91 in 2003 and $40.06 in 2002. During 2004, electricity prices were, relative to the cost of natural gas to generate electricity, improved from 2003. In January 2004, three Standard Offer contracts were extended on similar terms to those in effect for 2003. This volume represented approximately 77% of the Company’s electricity sales output. Under the terms of the Standard Offer contracts, the price received for the electricity is based on the cost of natural gas at the California border. The Company consumes approximately 37,000 MMBtu of natural gas per day for use in generating steam and of this total, approximately 72% is consumed in the Company’s cogeneration operations. By maintaining a correlation between electricity and natural gas prices, the Company is able to better control its cost of producing steam. Depending on the outcome of a proceeding that is currently under way at the CPUC to review and revise the methodology to determine SRAC energy prices, this correlation between electricity and natural gas prices may change at some point in the future.

Three of the SO contracts expired on December 31, 2004. However, by order of the CPUC in January 2004, the respective utilities were ordered to continue to offer SO1 contracts for an additional term of five years to certain QFs, such as the Company. In December 2004, the Company executed a five year contract with Edison for the Placerita Unit 2 facility, and five year contracts with PG&E for the Cogen 18 and Cogen 38 facilities, each effective January 1, 2005. Edison and PG&E have challenged, in the California Court of Appeal, the legality of the CPUC decision that ordered the utilities to enter into the one-year SO contracts for 2004, and the decision that ordered the utilities to enter five-year SO contracts. Arguments in this case were heard by the court in March 2005. Based on the current pricing mechanism for its electricity under the contracts, the Company expects that its electricity revenues will be in the $45 to $50 million range for 2005 and that these operations will be marginally profitable before any DD&A charges.

In 2002, the Company recorded income of $3.6 million, which represented the recovery of a portion of the $6.6 million of the receivables from electricity sales that were written off in 2001 due to non-payment by utilities contractually obligated to purchase the Company’s electricity.

Oil and Gas Operating Expenses. The Company believes 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 Company revised its allocation of cogeneration costs to oil and gas operations during 2004. Operating costs information has been revised to reflect this allocation which is based on the conversion efficiency (of fuel to electricity and steam) of the Company's cogeneration plants. The following table presents information about the Company's 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	$ 10.96	$ 10.36	6%	$ 82,419	$ 62,554	32%

DD&A	3.96	2.86	38%	29,752	17,258	72%
G&A	2.71	2.13	27%	20,354	12,868	58%
Interest expense	0.27	0.23	17%	2,067	1,414	46%
Total	$ 17.90	$ 15.58	15%	$ 134,592	$ 94,094	43%

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The Company's total operating expenses for 2004, stated on a unit-of-production basis, increased 15% over 2003. The increase was primarily related to the following items:

&#183 Operating costs for 2004, on a per barrel basis, increased 6% over 2003. The cost of the Company's steaming operations for its heavy oil properties represents a significant portion of the Company's 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. Steam costs were higher in 2004 as the cost for natural gas per MMBtu increased to $5.46 from $4.88 in 2003, an increase of 12%. The Company also injected an average of 69,200 BSPD in 2004, up 9% from 63,300 BSPD in 2003. Assuming stable crude oil and natural gas prices, the Company plans to inject steam at levels in 2005 comparable to 2004 levels and anticipates operating costs in 2005, on a per BOE basis, to average between $13.25 and $14.25 in its California operations, between $8.50 and $9.50 in its Utah operations and between $11.75 and $12.75 for the total Company.

· DD&A was $3.96 per BOE in 2004, up 38% from $2.86 per BOE in 2003. DD&A in 2004 was higher due to the shorter reserve life of the Brundage Canyon properties in Utah and the cumulative effect of increased development activities in recent years. The Company expects DD&A to trend higher over the next few years due to the shorter reserve life of the Rocky Mountain assets compared to the Company's California properties and continued development of its California and Rocky Mountain properties. The Company anticipates its oil and gas DD&A charges for 2005 will range from $4.25 to $4.75 per BOE.

· G&A expenses in 2004 were $2.71 per BOE, up 27% from $2.13 per BOE in 2003. Stock based compensation costs increased by $2.8 million in 2004, which are primarily non-cash charges resulting from mark-to-market adjustments under the variable method of accounting prior to the change of certain exercise provisions of the Company's stock option plan on July 29, 2004 and non-cash compensation expense under the fair value method of accounting. Compensation expenses increased by $2.3 million due to increased staffing resulting from the Company's growth, an increase in compensation levels and bonuses and costs related to a change in chief executive officers. Additionally, the Company incurred increased legal and accounting fees during 2004 of approximately $1 million, primarily due to compliance with Sarbanes-Oxley and other financial reporting related matters. For 2005, the Company anticipates that its G&A expenses will range from approximately $16 million to $19 million or $1.75 to $2.25 per BOE.

· Interest expense in 2004 was $.27 per BOE, up from $.23 per BOE in 2003. The Company’s borrowings at year-end 2004 were $28 million, down from $50 million in 2003. The Company borrowed $40 million in August 2003 to fund the acquisition of its Brundage Canyon property. The Company reduced its debt from 2003 levels during the latter half of 2004. Upon the close of its Niobrara gas acquisition in January of 2005 the Company’s outstanding borrowings rose to over $130 million. The Company anticipates that its interest cost for 2005 will be approximately $4 million to $5 million, or $.45 to $.60 per BOE.

The following table presents information about the Company's operating expenses for each of the years in the two-year period ended December 31, 2003:

	Amount per BOE			Amount (in thousands)		
	2003	2002	% Change	2003	2002	% Change

Operating costs	$	10.36	$	8.61	20%	$	62,554	$	45,217	38%
DD&A		2.86		2.55	12%		17,258		13,388	29%
G&A		2.13		1.75	22%		12,868		9,215	40%
Interest expense		0.23		0.20	15%		1,414		1,042	36%
Total	$	15.58	$	13.11	19%	$	94,094	$	68,862	37%

The Company's total operating expenses for 2003, stated on a unit-of-production basis, increased 19% over 2002. The increase was primarily related to the following items:

- Operating costs for 2003, on a per barrel basis, increased 20% over 2002. The cost of the Company's steaming operations for its heavy oil properties represents a significant portion of the Company's operating costs and will vary depending on both the cost of natural gas used as fuel in the steaming operations and the volume of steam injected during the year. Steam costs were higher in 2003 as the cost for natural gas per MMBtu increased to $4.88 from $3.13 in 2002. The Company also injected an average of 63,300 BSPD in 2003, up 5% from 60,060 BSPD in 2002.

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- DD&A was $2.86 per BOE in 2003, up 12% from $2.55 per BOE in 2002. DD&A in 2003 was higher due to the shorter reserve life of the Brundage Canyon properties in Utah and the cumulative effect of increased development activities in recent years.

- G&A expenses in 2003 were $2.13 per BOE, up 22% from $1.75 per BOE in 2002. The majority of the increase was due to stock option compensation of $3.9 million in 2003 compared to $1.3 million in 2002, which are primarily non-cash charges resulting from mark-to-market adjustments under the variable method of accounting. Also contributing to the increase in 2003 was higher compensation expenses, the opening of a regional office in the Rocky Mountains, a higher level of acquisition activity and increased accounting and consulting charges incurred in 2003.

- Interest expense in 2003 was $.23 per BOE, up from $.20 per BOE in 2002. The Company's borrowings at year-end 2003 were $50 million, up from $15 million in 2002 due to the acquisition of its Brundage Canyon properties in August 2003.

Electricity Operating Costs. The Company allocates cogeneration costs 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. As a result of this allocation, 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'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. As such, 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. The gross profit (sales of electricity less electricity operating costs) for the years ended December 31, 2004, 2003 and 2002 was $1.5 million, $1.8 million and $.9 million, respectively. On a per barrel basis, the Company views this gross profit as a decrease of $.19, $.32 and $.18 to the Company's total oil and gas operating expenses. DD&A related to the Company's cogeneration facilities is allocated between electricity operations and oil and gas operations using a similar allocation method.

Income Taxes. The Company experienced an effective tax rate of 23% in 2004, up from 12% and 20% reported in 2003 and 2002, respectively. The increase in effective tax rate during 2004 is primarily due to a much higher (over 100% increase) pre-tax income in 2004 over 2003. The Company's expansion outside of California and investment in non-thermal projects are also key factors in the increase. The Company is able to achieve an effective tax rate below the statutory tax rate of approximately 40% primarily as a result of significant EOR tax credits earned by the Company's continued investment in the development of its thermal EOR projects, both through capital expenditures and continued steam injection The Company believes it will continue to earn significant EOR tax credits. The Company expects its effective tax rate will trend higher as it diversifies its activities outside California and expects to have an effective tax rate in the 30% to 35% range in 2005, based on WTI prices averaging between $40 and $50.

Coalbed Methane Prospect. During 2002 and early 2003, the Company leased a total of approximately 208,000 net acres in Kansas and 54,000 net acres in Illinois to explore for economic concentrations of coalbed methane at a total lease cost of approximately $6 million. A five-well pilot was drilled in the Wabaunsee County portion of the Kansas acreage in the fourth quarter of 2002. After testing, the Company concluded that this pilot would not produce commercial quantities of natural gas and, therefore, wrote off the cost to drill these wells and the associated acreage in 2003 for a pre-tax charge to operations of $2.5 million.

In August 2003, the Company completed the sale of approximately 43,000 leased net acres in Jackson County, Kansas for approximately $1.7 million, while retaining an overriding royalty interest in the property. The Company recovered its cost associated with this acreage.

The Company also drilled a second five-well pilot in Jasper County, Illinois in the fourth quarter of 2002. After testing it was determined that gas volumes were not likely to be sufficient to realize commercial production; therefore, the costs to drill these wells and an impairment of the acreage was recorded in the fourth quarter of 2003, which resulted in a pre-tax charge of $1.7 million.

In 2005, the Company will evaluate if it is advantageous to retain the properties, but currently has no capital allocated for further testing of these properties.

Dry hole, Abandonment and Impairment. At December 31, 2004, the Company was in the process of drilling one exploratory well on its Midway-Sunset property and one exploratory well on its Coyote Flats prospect. These two wells were determined non-commercial in February 2005. Costs of $.5 million which were incurred as of December 31, 2004 were charged to expense and are reflected on the Company's income statement under "Dry-hole, abandonment and impairment." Remaining costs related to these wells are approximately $2.5 million which will be charged to expense during the first quarter of 2005.

During 2003, the Company recorded a pre-tax write down of $4.2 million related to two CBM pilot projects. For the periods ended December 31, 2004 and December 31, 2002, the fair value of the Company's oil and gas properties exceeded their carrying cost and as a result, the Company did not write down any of its oil and gas properties.

Other. In 2002, the Company recorded income of $3.6 million, which represented the recovery of receivables from electricity sales that were written off in 2001 due to non-payment by utilities contractually obligated to purchase the Company's electricity.

Financial Condition, Liquidity and Capital Resources

Substantial capital is required to replace and grow reserves. The Company achieves 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 the Company's cash flow from operating activities. The net long-term growth in the Company's cash flow from operating activities is the result of growth in production as affected by period to period fluctuations in commodity prices.

The Company establishes a capital budget for each calendar year based on its development opportunities and the expected cash flow from operations for that year. The Company may revise its capital budget during the year as a result of acquisitions and/or drilling outcomes. Excess cash generated from operations is normally applied to debt reduction during the year.

Working Capital and Cash Flows. The Company's working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under its credit arrangements. Generally, the Company uses excess cash to pay down borrowings under its credit arrangement. As a result, the Company often has a working capital deficit or a relatively small amount of positive working capital. Working capital as of December 31, 2004 was negative ($3.8) million, up from a negative ($3.5) million at December 31, 2003. Cash flow from operations is dependent upon the Company's ability to increase production through development, exploration and acquisition activities and the price of natural gas and oil. The Company's cash flow from operations also is impacted by changes in working capital. Net cash provided by operating activities increased to $125 million, up 92% from $65 million in 2003 and up 116% from $58 million in 2002. The increase in 2004 was a direct result of the increases in crude oil prices and production levels in 2004 compared to 2003 and 2002. Sales of oil and gas increased $91 million in 2004 compared to 2003, with crude oil prices, net of hedges, increasing 34% and production increasing 24% in 2004 compared to 2003. Cash flow was impacted by a 59% increase, or $19.2 million, in accounts payable and revenue and royalties payable due to increased capital expenditures in 2004, the continued development of both the California and Utah assets and due to a $9.1 million increase in a price sensitive royalty on one of the Company's California properties. Cash flow was also impacted by a 47% increase, or $11.1 million, in accounts receivable due to the increases in oil prices and production volumes and a full year of production at Brundage Canyon. The Company’s net decrease in borrowings on its credit line was $22 million in 2004. Cash was used for capital expenditures of $72 million, to fund $3 million in property acquisitions and to pay dividends of $11.4 million.

Capital Expenditures. Total capital expenditures in 2004, excluding acquisitions, were $72 million and included the drilling of 60 new wells and completing 34 workovers on its California properties and the drilling of 56 new wells and completion of 46 workovers on its Brundage Canyon properties in Utah.

Assuming stable oil and gas prices, excluding any future acquisitions in 2005, the Company plans to spend at least $107 million on capital projects including $36 million to drill 76 new wells and perform 38 workovers in California and $71 million to drill 107 new wells and perform 32 workovers in the Rocky Mountain and Mid-Continent regions from internally generated cash flow. With this increased development, the Company anticipates that production will average in excess of 23,000 BOE/day in 2005, up over 12% from an average 20,537 BOE per day in 2004.

Credit Facility. The Company successfully completed a new $200 million unsecured three-year credit facility in July 2003. The facility replaced the previous $150 million unsecured facility which was due to mature in January 2004. The 2003 facility recognizes the Company's strong financial position and provides significant low-cost capital for the Company to meet its growth objectives. In August 2003, the Company drew upon this facility to finance the $45 million purchase of the

Brundage Canyon, Utah assets. As of December 31, 2004, the Company had $172 million available under the facility. The Company drew on its credit facility to fund its acquisition of certain assets in the Niobrara field in January 2005. As of March 1, 2005, the Company's borrowing under its credit facility totaled $144 million. Exclusive of any further acquisitions in 2005, the Company plans to reduce debt levels from excess cash generated from operating activities.

The facility is a revolving credit facility for up to $200 million with ten banks. At December 31, 2004 and 2003, the Company had $28 million and $50 million, respectively, outstanding under the facility. In addition to the $28 million in borrowings under the Agreement, the Company has $.5 million of outstanding Letters of Credit and the remaining credit available under the facility is therefore, $172 million at December 31, 2004. The maximum amount available is subject to an annual borrowing base redetermination in accordance with the lenders' customary procedures and practices. The facility matures on July 10, 2006. Interest on amounts borrowed is charged at LIBOR plus a margin of 1.25% to 2.00%, or the higher of the lead bank's prime rate or the federal funds rate plus 50 basis points plus a margin of 0.0% to 0.75%, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. The Company pays a commitment fee of 30 to 50 basis points on the unused portion, which is also based on the ratio of credit outstanding to the borrowing base. Given that the credit markets have improved over the last year and the Company believes that its borrowing capacity has expanded, the Company intends to negotiate a new credit facility in 2005.

The weighted average interest rate on outstanding borrowings at December 31, 2004 was 3.37%. The facility contains restrictive covenants which, among other things, require the Company to maintain a certain tangible net worth and minimum EBITDA, as defined. The Company was in compliance with all such covenants as of December 31, 2004.

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 2004.

Contractual Obligations

The Company's contractual obligations as of December 31, 2004 are as follows (in thousands):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt	$ 28,000	$ -	$ 28,000	$ -	$ -
Abandonment obligations	8,214	304	871	1,064	5,975
Operating lease obligations	1,423	621	676	126	-
Drilling obligation	10,525	925	4,250	5,350	-
Firm natural gas transportation contract	23,438	2,814	5,628	5,628	9,368
Total	$ 71,600	$ 4,664	$ 39,425	$ 12,168	$ 15,343

Oil and Gas Hedging. From time to time, the Company enters into crude oil and natural gas hedge contracts, the terms of which depend on various factors, including Management's view of future crude oil prices and the Company's future financial commitments. This hedging program is designed to moderate the effects of a severe price downturn while allowing Berry to participate in the upside. Currently, the hedges are in the form of swaps, however, the

Company may use a variety of hedge instruments in the future. These hedging activities resulted in a net reduction in revenue per BOE to the Company of $3.31 in 2004, $1.96 in 2003 and $.72 in 2002.

While the use of these hedging arrangements reduces the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. The Company's oil hedges are based on reported settlement prices on the NYMEX. The basis risk between NYMEX and the Company's California heavy crude oil is mitigated by the Company's crude oil sales contract under which the Company sells over 90% of its California production. Pricing in the existing agreement is based upon the higher of the average of the local field posted prices plus a fixed premium, or WTI minus a fixed differential approximating $6.00 per barrel. This contract expires on December 31, 2005.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to the Company’s hedging activities, the Company utilizes multiple counterparties on its hedges and monitors each counterparty’s credit rating.

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 and natural gas 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 on 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. For its unproved properties, the Company performs an impairment analysis annually or whenever events or changes in circumstances indicate an asset’s net book carrying value may not be recoverable. 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 and costs to extract these reserves.

Derivatives and Hedging. The Company follows the provisions of Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS 133 requires the accounting recognition of all derivative instruments as either assets or liabilities at fair value. Derivative instruments that are not hedges must be adjusted to fair value through net income. Under the provisions of SFAS 133, the Company may designate a derivative instrument as hedging the exposure to change in fair value of an asset or liability that is attributable to a particular risk (a fair value hedge) or as hedging the exposure to variability in expected future cash flows that are attributable to a particular risk (a cash flow hedge). Both at the inception of a hedge and on an ongoing basis, a fair value hedge must be expected to be highly effective in achieving offsetting changes in fair value attributable to the hedged risk during the periods that a hedge is designated. Similarly, a cash flow hedge must be expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. The expectation of hedge effectiveness must be supported by matching the essential terms of the hedged asset, liability or forecasted transaction to the derivative contract or by effectiveness assessments using statistical measurements. The Company's policy is to assess hedge effectiveness at the end of each calendar quarter.

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Income Taxes. The Company computes income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*. SFAS No. 109 requires an asset and liability approach which results in the recognition of deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the Company's financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Additionally, the Company's federal and state income tax returns are generally not filed before the financial statements are prepared, therefore the Company estimates the tax basis of its assets and liabilities at the end of each calendar year as well as the effects of tax rate changes, tax credits, and tax credit carryforwards. Adjustments related to differences between the estimates used and actual amounts reported are recorded in the period in which income tax returns are filed. These adjustments and changes in estimates of asset recovery could have an impact on results of operations. The Company generates enhanced oil recovery tax credits from the production of its heavy crude oil in California which results in a deferred tax asset. The Company believes that these credits will be fully utilized in future years and consequently has not recorded any valuation allowance related to these credits. Due to uncertainties involved with tax matters, the future effective tax rate may vary significantly from the estimated current year effective tax rate.

Asset Retirement Obligations. The Company has significant obligations to plug and abandon oil and natural gas wells and related equipment at the end of oil and gas production operations. The computation of the Company's asset retirement obligations (ARO) was prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires the Company to record the fair value of liabilities for retirement obligations of long-lived assets. The adoption of SFAS No. 143 in 2002 resulted in an immaterial difference in the liability that had been previously recorded by the Company. Estimating the future ARO requires Management to make estimates and judgments regarding timing, current estimates of plugging and abandonment costs, as well as what constitutes adequate remediation. The Company obtained estimates from third parties and used the present value of estimated cash flows related to its ARO to determine the fair value. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Changes in any of these assumptions can result in significant revisions to the estimated ARO. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment will be made to the related asset. Due to the subjectivity of assumptions and the relatively long life of the Company's assets, the costs to ultimately retire the Company's wells may vary significantly from previous estimates.

Environmental Remediation Liability. The Company reviews, on a quarterly basis, its estimates of costs of the cleanup of various sites including sites in which governmental agencies have designated the Company as a potentially responsible party. In accordance with SFAS No. 5, *Accounting for Contingencies,* when it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of remediation can be determined, the applicable amount is accrued. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is an estimation process that includes the subjective judgment of Management. In many cases, Management's judgment is based on the advice and opinions of legal counsel and other advisers, the interpretation of laws and regulations, which can be interpreted differently by regulators or courts of law, the experience of the Company and other companies in dealing with similar matters and the decision of Management on how it intends to respond to a particular matter. A change in estimate could impact the Company's oil and gas operating costs and the liability, if applicable, recorded on the Company's balance sheet.

Recent Accounting Developments

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS 123(R), *Share-Based Payments*, which is a revision of SFAS 123. SFAS 123(R) supersedes APB 25 and amends Statement of Accounting Standards No. 95, *Statement of Cash Flows*. Generally, the approach in SFAS 123(R) will require all share-based payments to employees, including grants of employee stock options, to be recognized based on their fair values. SFAS 123(R) must be adopted by the Company no later than the third quarter of 2005. The Company voluntarily adopted SFAS 123 as of January 1, 2004 and does not expect SFAS 123(R) will have a material impact on the Company's financial position, net income or cash flows.

In December 2004, the FASB issued FASB Staff Position (FSP) FAS 109-1, *Application of FASB Statement No. 109, Accounting for Income Taxes, for the Tax Deduction Provided to U.S. Based Manufacturers by the American Jobs Creation Act of 2004*, This position clarifies how to apply SFAS No. 109 to the new law's tax deduction for income attributable to "domestic production activities." The Company does not expect this statement will have a material impact on the Company's financial position, net income or cash flows.

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In January 2005, the FASB issued SFAS No. 153, *Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 28*. This statement, which addresses the measurement of exchanges of nonmonetary assets, is effective prospectively for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The adoption of this statement is not expected to impact the Company's financial position, net income, or cash flows.

Impact of Inflation

The impact of inflation on the Company has not been significant in recent years because of the relatively low rates of inflation experienced in the United States.

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 the Company's business. The Company's revenues, profitability and future growth depend substantially on reasonable prices for oil and gas. These prices also affect the amount of cash flow available for capital expenditures and the ability to borrow and raise additional capital. The amount the Company can borrow under its 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 can be economically produced.

Among the factors that can cause fluctuations are:

- the domestic and foreign supply of oil and natural gas;
- the price and availability of alternative fuels;
- weather conditions;
- the level of consumer demand;
- the price of foreign imports;
- world-wide economic conditions;
- political conditions in oil and gas producing regions;
- the change in the value of the U.S. dollar as global oil prices are priced in U. S. dollars; and
- domestic and foreign governmental regulations.

The Company's heavy crude in California is less economic than lighter crude oil and natural gas. As of December 31, 2004, approximately 88% of the Company's proved reserves, or 97 million barrels, consisted of heavy oil. Heavy oil sells for less than light sweet crudes, over the past ten years, approximately $6.00 per barrel less. However, this differential widened during 2004, averaging $8.57 and has averaged over $14.00 during the first two months of 2005. Additionally, most of the Company's heavy oil production requires heat, in the form of steam, to mobilize the oil for production from the wellbore. Steam costs represent a significant portion of the Company's operating costs and are costs that the production of light crude oil or natural gas do not have. This thermal enhanced process and the related costs further reduce the Company's margins on its heavy crude oil. The Company consumes natural gas to generate steam and thus is at risk when natural gas prices rise without a corresponding rise in crude oil prices.

A widening of commodity differentials may adversely impact the Company's revenues and per barrel economics. Both the Company's produced crude oil and natural gas is subject to pricing in the local markets where the production occurs. It is customary that such product is priced based on local or regional supply and demand factors. California heavy crude sells at a substantial discount to WTI, the U.S. benchmark crude oil, primarily due to the additional cost to refine more gasoline or light product out of a barrel of heavy crude. The Company's Utah light crude also is normally priced below WTI. Natural gas field prices are normally priced off of NYMEX traded prices or Henry Hub, the benchmark for U.S. natural gas. While the Company attempts to contract for the best possible price in each of its 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, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the business, trade restrictions, governmental regulations, etc. The Company may be adversely impacted by a widening differential on the products it sells.

The future of the electricity market in California is uncertain. The Company utilizes cogeneration plants in California to generate lower cost steam compared to conventional steam generation methods. Electricity produced by the Company's cogeneration plants is sold to utilities and the steam costs are allocated to the Company’s oil and gas operations. While the Company has new five-year electricity sales contracts in place with the utilities beginning on January 1, 2005, legal and regulatory decisions, especially related to the pricing of electricity under the contracts, can adversely affect the economics of the Company’s cogeneration facilities and thereby, the cost of steam for use in the Company’s oil and gas operations. In addition, the utilities are seeking to overturn the CPUC order to offer such contracts.

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The Company may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. The Company may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. The Company is dependent on several cogeneration facilities that provide over half of its steam requirement. These facilities are dependent on reasonable electrical contracts to provide economic steam for use in the Company's operations. If, for any reason, the Company was unable to enter into an electrical contract or were to lose an existing contract, the Company may not be able to supply 100% of the steam requirements necessary to maximize production from its heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam. The financial cost and timing of such investment may adversely affect the Company's production and cash provide by operating activities.
A shortage of natural gas in California could adversely affect the Company's business. The Company may be subject to the risks associated with a shortage of natural gas and/or the transportation of natural gas into California. The Company is highly dependent on sufficient volumes of natural gas that it uses for fuel in generating steam for use in its heavy oil operations in California. If the required volume of natural gas for use in its operations were to be unavailable or too highly priced to produce heavy oil economically, the Company's production could be adversely impacted.

The Company's 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. The Company uses hedging transactions with respect to a portion of its oil and gas production to achieve more predictable cash flow and to reduce its 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's future success depends on its ability to find, develop and acquire oil and gas reserves. To maintain production levels, the Company must locate and develop or acquire new oil and gas reserves to replace those depleted by production. Without successful exploration, exploitation or acquisition activities, the Company's reserves, production and revenues will decline. The Company 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 the Company's cash flow from operations being less than expected or limit its ability to borrow under credit arrangements, the Company 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 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, some of which are mandated by the Securities and Exchange Commission (SEC), such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Actual quantities of recoverable oil and gas reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates. Any significant variance could materially affect the quantities and present value of the Company's reserves. In addition, the Company 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, the Company bases 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 and gas prices decrease, the Company may be required to take writedowns. The Company may be required to writedown the carrying value of its oil and gas properties when oil and gas prices are low, including basis differentials, or there are substantial downward adjustments to its estimated proved reserves, increases in estimates of development costs or deterioration in exploration or production results.

The Company capitalizes costs to acquire, find and develop its oil and gas properties under the successful efforts accounting method. The net capitalized costs of the Company's oil and gas properties may not exceed the fair market value.

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If net capitalized costs of its oil and gas properties exceed fair value, the Company must charge the amount of the excess to earnings. The Company reviews the carrying value of its 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.

The Company may be subject to risks in connection with acquisitions. The successful acquisition of producing properties requires an assessment of several factors, including:

- reserves;
- future oil and gas prices;
- operating costs;
- title to properties; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, the Company performs a review of the subject properties that it believes to be generally consistent with industry practices. A review will not necessarily reveal all existing or potential problems nor will it permit the Company to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. The Company often is not entitled to contractual indemnification for certain liabilities and acquires properties on an “as is” basis.

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 the Company's competitors have financial resources that are substantially greater, which may adversely affect the Company's ability to compete with these companies.

Drilling is a high-risk activity. The Company's future success will partly depend on the success of its drilling program. In addition to the numerous operating risks described in more detail below, these activities involve the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the Company is 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.

The oil and gas business involves many operating risks that can cause substantial losses; insurance may not protect the Company 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.

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

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

If the Company experiences any of these problems, its ability to conduct operations could be adversely affected.

The Company maintains insurance against some, but not all, of these potential risks and losses. The Company may elect not to obtain insurance if it believes that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect the Company.

The Company is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business. The Company's development, exploration, production and marketing operations are regulated extensively at the federal, state and local levels. In addition, a portion of the Company's leases in the Uinta Basin are, and some of the Company's 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, the Company 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 the Company's operations and subject it to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which the Company operates 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, the Company's activities are subject to the regulation by oil and natural gas-producing states and Native American tribes of conservation practices and protection of correlative rights. These regulations affect the Company's operations and limit the quantity of oil and natural gas the Company may produce and sell. A major risk inherent in the Company's drilling plans is the need to obtain drilling permits from state, local and Native American tribal authorities. Delays in obtaining regulatory approvals, 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 material adverse effect on the Company's 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 the Company's profitability.

Other independent oil and gas companies' limited access to capital may change the Company's development and exploration plans. Many independent oil and gas companies have limited access to the capital necessary to finance their activities. As a result, some of the other working interest owners of the Company's wells may be unwilling or unable to pay their share of the costs of projects as they become due. These problems could cause the Company to change, suspend or terminate drilling and development plans with respect to the affected project.

Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business.

API gravity - The industry standard method of expressing specific gravity of crude oils. Higher API gravities mean lower specific gravity and lighter oils.

Basis risk - The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular hedging transaction.

Bbl - One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or condensate.

Bcf - Billion cubic feet.

Bcfe - Billion cubic feet equivalent, determined using the ratio of six Mcf gas to one Bbl of crude oil or condensate.

BOE - Barrel of Oil equivalent.

BSPD - Barrels of steam per day.

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Btu - British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

California Public Utilities Commission (CPUC) - A California government agency which regulates privately owned electric, telecommunications, natural gas, water and transportation companies.

Cash-flow hedge - Derivative instruments used to mitigate the risk of variability in cash flows from crude oil and natural gas sales due to changes in market prices. These derivative instruments either fix the price a party receives for its production or, in the case of option contracts, set a minimum price or a price within a fixed range.

Cogeneration - The simultaneous production of steam and electricity using a single fuel source (natural gas).

Completion - The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

DD&A - Depreciation, Depletion and Amortization

Developed acreage - The number of acres that are allocated or assignable to producing wells or wells capable of production.

Development well - A well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive, including a well drilled to find and produce probable reserves.

Dry hole or well - A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Enhanced Oil Recovery (EOR) - Efforts to improve the flow of oil from a reservoir that has already been produced by conventional means.

Exploitation - Drilling wells in areas proven to be productive.

Exploration or exploratory well - A well drilled to find and produce oil or natural gas reserves that is not a development well.

Farm-out - A transfer of all or part of the operating rights from the working interest owner to an asignee, who assumes all or some of the burden of development, in return for an interest in the property.

Federal Energy Regulatory Commission (FERC) - A government agency which regulates the transmission of oil and natural gas by pipeline and wholesale sales of electricity in interstate commerce.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Gross acres or gross wells - The total acres or wells in which a working interest is owned.

Heavy oil - Oil with an API gravity below 20 degrees.

Henry Hub (HH) - The standard delivery point for natural gas traded on the New York Mercantile Exchange (Sabine Pipe Line Company's Henry Hub in Louisiana).

Infill drilling - Drilling wells between established producing wells on a lease; a drilling program to reduce the spacing between wells in order to increase production and/or recovery of in-place hydrocarbons from the lease.

Kilowatt (KW) - 1,000 watts, which are the standard measure of electrical power

MBbls - One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf - One thousand cubic feet.

Mcfe - One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or condensate.

Megawatt (MW) - One million watts.

MMS - The Minerals Management Service of the United States Department of the Interior.

MMBbls - One million barrels of crude oil or other liquid hydrocarbons.

MMcf - One million cubic feet.

MMcfe - One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or condensate.

Net acres or net wells - The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NYMEX - The New York Mercantile Exchange.

Productive well - A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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Proved developed producing reserves - Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves - Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved developed nonproducing reserves - Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved reserves - The estimated quantities of crude oil or natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves - Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Public Utility Regulatory Policies Act of 1978 (PURPA) - Federal regulation which provides incentives for the development of cogeneration facilities such as those owned by the Company.

Qualifying Facilities (QF) - A cogeneration facility which produces 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 which meets certain energy efficiency standards.

Short Run Avoided Cost (SRAC) - An energy payment that reflects the utility's avoided short-term variable cost to produce electricity.

Undeveloped acreage - Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

West Texas Intermediate (WTI) - The benchmark United States crude oil with an API gravity of approximately 40 degrees.

Working interest - The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover - Operations on a producing well to restore or increase production.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Price Risk Management. From time to time, the Company enters into crude oil and natural gas hedge contracts, the terms of which depend on various factors, including Management's view of future crude oil and natural gas prices and the Company's future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil price downturn and protect certain operating margins in the Company's California operations. Currently, the hedges are in the form of swaps, however, the Company may use a variety of hedge instruments in the future. The Company generally attempts to hedge between 25% and 50% of its anticipated crude oil production and up to 30% of its anticipated net natural gas purchased each year. Management regularly monitors the crude oil and natural gas markets and the Company's financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging or other price protection is appropriate. All of these hedges have historically been deemed to be cash flow hedges with the mark-to-market valuations provided by external sources, based on prices that are actually quoted.

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As of December 31, 2004, the Company had hedge positions for 2005 of approximately 7,750 barrels per day of crude oil production at an average WTI price of approximately $40.75 and 7,500 MMBtu per day of natural gas consumption at an average SoCal price of approximately $5.25. At December 31, 2004 the Company had hedge positions for 2006 of 5,000 MMBtu per day through June 2006 at an average SoCal price of $4.85 and 1,000 MMBtu per day of natural gas production at a CIG price of $6.21. In 2004, the average differential between SoCal and Henry Hub (HH) was approximately $.60 per MMBtu and the differential between CIG and HH was approximately $1.00 per MMBtu. Based on NYMEX futures prices at December 31, 2004, (WTI $42.66; HH $6.32) the Company would expect future cash payments or receipts, over the remaining term of its existing crude oil and natural gas hedges, on a pre-tax basis, as follows:

	12/31/04 NYMEX Futures	Impact of percent change in futures prices on earnings (in thousands) -30%	-15%	+ 15%	+ 30%
Average WTI Price	$ 42.66	$ 29.86	$ 36.26	$ 49.05	$ 55.45
Crude Oil gain/(loss)	(5,098)	31,102	13,002	(23,199)	(41,299)
Average HH Price	6.32	4.43	5.38	7.27	8.22
Natural Gas gain/(loss)	2,625	(3,216)	(295)	5,545	8,466

The Company sells 100% of its electricity production, net of electricity used in its oil and gas operations, under SO contracts to major utilities. Three of the four SO contracts representing approximately 77% of the Company's electricity for sale expired in one-year contracts on December 31, 2003. However, as ordered by CPUC, the utilities offered and the Company accepted one-year extensions on these contracts in January 2004 and as order by the CPUC in late 2004, has entered into new five-year contracts with the utilities. However, the sales price under these contracts are subject to regulatory review and the pricing methodology may not be linked to natural gas prices in the future. The Company sells the remaining 20 MWh to a utility at $53.70 per MWh plus capacity through a long-term sales contract that expires in June 2006.

Credit Risk. The Company attempts to minimize credit exposure to counterparties through monitoring procedures and diversification. The Company's exposure to changes in interest rates results primarily from long-term debt. Total debt outstanding at December 31, 2004 and 2003 was $28 million and $50 million, respectively. Interest on amounts borrowed is charged at LIBOR plus 1.25% to 2.0%. Based on year-end 2004 borrowings, a 1% change in interest rates would not have a material impact on the Company's financial statements.

Commodity Price Risk. During 2004, WTI prices per barrel reached a high of $55.17, a low of $32.48 and averaged $41.47 for the year compared to an average of $30.99 and $26.15 in 2003 and 2002, respectively. The price of crude oil is influenced by many factors both regionally and globally. Additionally, approximately 83% of the Company's current production is California heavy crude oil. California heavy crude oil has sold at a discount of approximately $6.00 to WTI over the past ten years. The basis risk between WTI and the Company's California heavy crude oil is mitigated by the Company's crude oil sales contract under which the Company sells over 90% of its California production. Pricing in the existing agreement is based upon the higher of the average of the local field posted prices plus a fixed premium, or WTI minus a fixed differential approximating $6.00 per barrel. This contract expires on December 31, 2005.

During 2004 and through early 2005, the differential between California heavy crude oil and WTI widened to over $14.00 per barrel and averaged $8.57 in 2004. While the Company is confident that it will be able to secure a contract for its California heavy crude oil in future periods, it is unlikely that the Company will be able to obtain terms similar to the current contract. In 2004, the Company estimates that its revenues benefited from this contract by approximately $13 million, and at a current differential of approximately $14.00 per barrel, the Company estimates that its revenues in 2005 will benefit from the contract by approximately $45 million.

Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" With the exception of historical information, the matters discussed in this news release are forward-looking statements that involve risks and uncertainties. Although the Company believes that its expectations are based on reasonable assumptions, it can give no assurance that its goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to: the timing and extent of changes in commodity prices for oil, gas and electricity; development, exploration, drilling and operating risks; a limited marketplace for electricity sales within California, counterparty risk; acquisition risks; competition, environmental risks, litigation uncertainties; the availability of drilling rigs and other support services, legislative and/or judicial decisions and other government or Tribal regulations.

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Item 8. **Financial Statements and Supplementary Data**

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed an integrated audit of Berry Petroleum Company's 2004 financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Financial statements
In our opinion, the accompanying balance sheets and the related statements of income, comprehensive income, cash flows and shareholders' equity present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, effective January 1, 2004, the Company changed its method of accounting for stock-based compensation to conform to Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation."

Internal control over financial reporting
Also, in our opinion, management's assessment, included in "Management's Report on Internal Control Over Financial Reporting" appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control — Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Los Angeles, California
March 30, 2005

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BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2004 and 2003
(In Thousands, Except Share Information)

		2004		2003
ASSETS				
Current assets:				
Cash and cash equivalents	$	16,690	$	10,658
Short-term investments available for sale		659		663
Accounts receivable		34,621		23,506
Deferred income taxes		3,558		6,410
Fair value of derivatives		3,243		-
Prepaid expenses and other		2,230		2,049
Total current assets		61,001		43,286
Oil and gas properties (successful efforts basis), buildings and equipment, net		338,706		295,151
Deposits on potential property acquisitions		10,221		-
Other assets		2,176		1,940
	$	412,104	$	340,377
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	27,750	$	20,867
Revenue and royalties payable		23,945		11,623
Accrued liabilities		6,132		4,214
Income taxes payable		1,067		4,412
Fair value of derivatives		5,947		5,710
Total current liabilities		64,841		46,826
Long-term liabilities:				
Deferred income taxes		47,963		38,559
Long-term debt		28,000		50,000
Abandonment obligation		8,214		7,311
Fair value of derivatives		-		343
		84,177		96,213
Commitments and contingencies (Notes 10 and 11)				
Shareholders' equity:				
Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding		-		-
Capital stock, $.01 par value:				
Class A Common Stock, 50,000,000 shares authorized; 21,060,420 shares issued and outstanding (20,904,372 in 2003)		210		209
		9		9

Class B Stock, 1,500,000 shares authorized; 898,892 shares issued and outstanding (liquidation preference of $899)				
Capital in excess of par value		60,676		56,475
Deferred stock-based compensation		-		(1,108)
Accumulated other comprehensive loss		(987)		(3,632)
Retained earnings		203,178		145,385
Total shareholders' equity		263,086		197,338
	$	412,104	$	340,377

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

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BERRY PETROLEUM COMPANY
Statements of Income
Years ended December 31, 2004, 2003 and 2002
(In Thousands, Except Per Share Data)

	2004	2003	2002
Revenues:			
Sales of oil and gas	$ 226,876	$ 135,848	$ 102,026
Sales of electricity	47,644	44,200	27,691
Interest and dividend income	261	236	536
Other income	165	580	1,116
	274,946	180,864	131,369
Expenses:			
Operating costs – oil and gas production	82,419	62,554	45,217
Operating costs – electricity generation	46,191	42,351	26,747
Depreciation, depletion & amortization - oil and gas	29,752	17,258	13,388
Depreciation, depletion & amortization - electricity generation	3,490	3,256	3,064
General and administrative	20,354	12,868	9,215
Interest	2,067	1,414	1,042
Loss on disposal of assets	410	-	-
Dry hole, abandonment and impairment	745	4,195	-
Recovery of electricity receivable	-	-	(3,631)
	185,428	143,896	95,042
Income before income taxes	89,518	36,968	36,327
Provision for income taxes	20,331	4,605	7,117
Net income	$ 69,187	$ 32,363	$ 29,210
Basic net income per share	$ 3.16	$ 1.49	$ 1.34
Diluted net income per share	$ 3.08	$ 1.47	$ 1.33
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,894	21,772	21,741
Effect of dilutive securities:			
Stock options	523	215	115
Other	53	44	46
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,470	22,031	21,902

Statements of Comprehensive Income
Years Ended December 31, 2004, 2003 and 2002
(In Thousands)

Net income	$	69,187	$	32,363	$	29,210
Unrealized gains (losses) on derivatives, net of income taxes of ($521), ($709), and ($1,712)		(781)		(3,632)		(2,569)
Reclassification of unrealized losses included in net income net of income taxes of $2,284, $1,712 and $0		3,426		2,569		-
Comprehensive income	$	71,832	$	31,300	$	26,641

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

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BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2004, 2003 and 2002
(In Thousands, Except Per Share Data)

	Class A	Class B	Par Value	Compensation	Earnings	Comprehensive Income (Loss)	Equity