BERRY PETROLEUM CO
Form 10-K
February 28, 2007

**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, 2006**
Commission file number **1-9735**

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

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

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

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

Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Name of each exchange on which registered |
|---|---|
| **Class A Common Stock, $.01 par value (including associated stock purchase rights)** | **New York Stock Exchange** |

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES x NO o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
YES o NO x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filerx Accelerated filero Non-accelerated filero
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO x

As of June 30, 2006, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $1,202,477,929. As of February 9, 2007, the registrant had 42,120,651 shares of Class A Common Stock outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on February 9, 2007 all of which are held by an affiliate of the registrant.

DOCUMENTS INCORPORATED BY REFERENCE

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

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**PART I**

**Item 1. Business**

**General.** We are an independent energy company engaged in the production, development, acquisition, exploitation of and exploration for, crude oil and natural gas. While we were incorporated in Delaware in 1985 and have been a publicly traded company since 1987, we can trace our roots in California oil production back to 1909. In 2003, we purchased and began operating properties in the Rocky Mountain/Mid-Continent region. Our corporate headquarters are in Bakersfield, California and we have a regional office in Denver, Colorado. Information contained in this report on Form 10-K reflects our business during the year ended December 31, 2006 unless noted otherwise.

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

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

- ***Developing our existing resource base.*** We intend to increase both production and reserves annually. We are focused on the timely and prudent development of our large resource base through developmental and step-out drilling, down-spacing, well completions, remedial work and by application of enhanced oil recovery (EOR) methods and optimization technologies, as applicable. In 2006, we invested in a large undeveloped probable reserve position in the Piceance basin in Colorado, and are planning for significant drilling there over the next several years. We also have large hydrocarbon resources in place in the San Joaquin Valley basin, California (diatomite) and an emerging resource play in the Uinta basin, Utah (Lake Canyon). We have a proven track record of developing reserves and increasing production in all of our operating regions.
- ***Acquiring additional assets with significant growth potential.*** We will continue to evaluate oil and gas properties with proved reserves, probable reserves and/or sizeable acreage positions that we believe contain substantial hydrocarbons which can be developed at reasonable costs. We have identified the Rocky Mountain/Mid-Continent region as our primary area of interest for growth. Significant recent acquisitions in the region include: $105 million acquisition in 2005 of mostly proved reserves in the Niobrara gas play in the Denver-Julesburg (DJ) basin and two transactions in 2006 pursuant to which we have committed over $312 million to acquire or earn natural gas acreage in the Piceance basin. We will continue to review asset acquisitions that meet our economic criteria with a primary focus on large repeatable development potential in these regions. Additionally, we seek to increase our net revenue interest in assets that we already operate. In California, we continue to evaluate available properties for acquisition to take advantage of our extensive operational and technical expertise in the development and production of heavy oil.
- ***Utilizing joint ventures with respected partners to enter new basins.*** We believe that early entry into some basins offers the best potential for establishing low cost acreage positions in those basins. In areas where we do not have existing operations, we seek to utilize the skills and knowledge of other industry participants upon entering these new basins so that we can reduce our risk and improve our ultimate success in the area.
- ***Accumulating significant acreage positions near our producing operations.*** We have been successful in adding strategic acreage positions in less than three years with the intent of appraising the potential of the acreage for the economic production of hydrocarbons. As of December 31, 2006 these positions include 483,000 and 145,400 gross acres in the DJ and Uinta basins, respectively, which are adjacent to, or in the proximity of, our producing assets within those basins. This strategy allows us to leverage our operating and technical expertise within the area and build on established core operations. We are appraising these acreage blocks by shooting and utilizing 3-D seismic

data, participating in drilling programs in areas of mutual interest with partners and utilizing current geological, geophysical and drilling technologies. We also intend to pursue acreage in large resource plays that may result in repeatable-type development.

- ***Investing our capital in a disciplined manner and maintaining a strong financial position.*** The oil and gas business is capital intensive. Therefore we will focus on utilizing our available capital on projects where we are likely to have success in increasing production and/or reserves at attractive returns. We believe that maintaining a strong financial position will allow us to capitalize on investment opportunities and be better prepared for a lower commodity price environment. We expect to continue to hedge oil and gas prices and to utilize long-term sales contracts with the objective of achieving the cash flow necessary for the development of our assets.

***Business strengths.***

- ***Balanced high quality asset portfolio with a long reserve life.*** Since 2002, we have grown and diversified our California heavy oil asset base through acquisitions in three core areas in the Rocky Mountain/Mid-Continent region that have significant growth potential. Our base of legacy California assets provides us with a steady stream of cash flow to re-invest into our significant drilling inventory and the appraisal of our prospects. Our wells are generally characterized by long production lives and predictable performance. At December 31, 2006 our implied reserve life was 15.3 years and our implied proved developed reserve life was 10.4 years.
- ***Track record of efficient proved reserve and production growth.*** For the three years ended December 31, 2006, our average annual reserve replacement rate was 260% at an average cost of $12.74 per barrel of oil equivalent (BOE). See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operation for further explanation of the reserve replacement rate. During the same period our proved reserves and production increased at an annualized compounded rate of 11.2% and 15.7%, respectively. We were able to deliver that growth predominantly through low-risk drilling. We have achieved an average drilling success rate of 98%. We believe we can continue to deliver strong growth through the drill bit by exploiting our large undeveloped leasehold position. We also plan to complement this drill bit growth through selective and focused acquisitions.
- ***Experienced management and operational teams.*** We have significantly expanded and deepened our core team of technical staff and operating managers, who have broad industry experience, including experience in California heavy oil thermal recovery operations and Rocky Mountain tight gas sands development and completion. We continue to utilize technologies and steam practices that we believe will allow us to improve the ultimate recoveries of crude oil on our mature California properties. We also utilize 3-D seismic technology for evaluation of sub-surface geologic trends of our many prospects.
- ***Operational control and financial flexibility.*** We exercise operating control over approximately 99% of our proved reserve base. We generally prefer to retain operating control over our properties, allowing us to control operating costs more effectively, the timing of development activities and technological enhancements, the marketing of production and the allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary which allows us a significant degree of flexibility to adjust the size and timing of our capital budget. We finance our drilling budget primarily through our internally generated operating cash flows and we also have a $750 million senior unsecured revolving credit facility with a current borrowing base of $500 million.
- ***Established risk management policies.*** We actively manage our exposure to commodity price fluctuations by hedging a material portion of our forecasted production. We use hedges to help us mitigate the effects of price declines and to secure operating cash flows in order to fund our capital expenditures program. Our long-term crude oil contracts with refiners and our long-term firm natural gas pipeline transportation agreements help us mitigate price differential volatility and assure product delivery to markets. The operation of our cogeneration facilities provides a partial hedge against increases in natural gas prices because of the high correlation between electricity and natural gas prices under our electricity sale contracts.

***Proved Reserves and Revenues.*** As of December 31, 2006, our estimated proved reserves were 150.3 million BOE, of which 66% are heavy crude oil, 9% light crude oil and 25% natural gas. We have a geographically diverse asset base with 66% of our reserves located in California, and 34% in the Rocky Mountain/Mid-Continent region. Of our proved reserves 68% were proved developed. Proved undeveloped reserves make up 32% of our proved total. The projected capital to develop these proved undeveloped reserves is $382 million, at an estimated cost of approximately $7.96 per BOE. Approximately 78% of the capital to develop these reserves is expected to be expended in the next five years. Production in 2006 was 9.3 million BOE, up 11% from production of 8.4 million BOE in 2005.

Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics with a ratio of proved reserves to production (based on the year ended December 31, 2006) of approximately 15.3 years as compared to 14.6 years at year-end 2005.

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We have six asset teams, three in California and three in the Rocky Mountain/Mid-Continent region. California's three teams are South Midway-Sunset (SMWSS), North Midway-Sunset (NMWSS) (which includes diatomite) and Southern California (Socal) (which includes Poso Creek, Ethel D, Placerita and Montalvo). The three Rocky Mountain/Mid-Continent region teams are DJ, Uinta and Piceance. The following table sets forth the estimated quantities of proved reserves and production attributable to our asset teams as of December 31, 2006. We operate 99% of these assets:

| State | Name | Type | Average Daily Production (BOE/D) | % of Daily Production | Proved Reserves (BOE) in thousands | % of Proved Reserves | Oil & Gas Revenues before hedging (in millions) | % of Oil & Gas Revenues |
|---|---|---|---|---|---|---|---|---|
| CA | SMWSS | Heavy oil | 10,101 | *39.8%* | 50,124 | *33.4%* | $179.3 | *40.2%* |
| UT | Uinta | Light oil/Natural gas | 5,949 | *23.4* | 21,093 | *14.0* | 101.1 | *22.7* |
| CA | Socal | Heavy oil | 4,824 | *19.0* | 33,441 | *22.2* | 100.8 | *22.6* |
| CO | DJ | Natural gas | 2,676 | *10.5* | 18,620 | *12.4* | 34.0 | *7.6* |
| CA | NMWSS | Heavy oil | 1,125 | *4.4* | 16,343 | *10.9* | 23.8 | *5.3* |
| CO | Piceance | Natural gas | 723 | *2.9* | 10,641 | *7.1* | 7.3 | *1.6* |
| **Totals** | | | **25,398** | ***100%*** | **150,262** | ***100%*** | **$446.3** | ***100%*** |

We continue to engage DeGolyer and MacNaughton (D&M) to appraise the extent and value of our proved oil and gas reserves and the future net revenues to be derived from our properties for the year ended December 31, 2006. 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 our reserves. 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, 2006. See Supplemental Information About Oil & Gas Producing Activities (Unaudited) for our oil and gas reserve disclosures.

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

***Operations.*** In California, we operate all of our principal oil and gas producing properties. The Midway-Sunset and Socal assets contain predominantly heavy crude oil which requires heat (except Montalvo, which averages production from below 11,500 feet deep), supplied in the form of steam, which is injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. We utilize cyclic steam and/or steam flood recovery methods on all assets in addition to primary recovery methods at our Montalvo field. Field operations related to oil production include the initial recovery of the crude oil and its transport through treating facilities into storage tanks. After the treating process is completed, which includes removal of water and solids by mechanical, thermal and chemical processes, the crude oil is metered through automatic custody transfer units or gauged before sale and subsequently transferred into crude oil pipelines owned by other companies or transported via truck.

In the Rocky Mountain/Mid-Continent region, crude oil produced from the Uinta assets is transported by truck, while its gas production, net of field usage, is transported by gathering or distribution systems to the Questar Pipeline. Natural gas produced from the DJ basin gas assets is transported to one of three main pipelines. Our Piceance basin natural gas is gathered and sold to an affiliate of our industry partner. We have pipeline gathering systems and gas compression facilities for delivery into various interstate gas lines.

**Crude Oil and Natural Gas Marketing.**

***Economy.*** The global and California crude oil markets continue to remain strong though volatile. Product prices continued to exhibit an overall-strengthening trend through August 2006 and then retreated somewhat. The range of West Texas Intermediate (WTI) crude prices for 2006, based upon NYMEX settlements, was a low of $55.81 and a high of $77.03. We expect that crude prices will continue to be volatile in 2007.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Average NYMEX settlement price for WTI | $ 66.25 | $ 56.70 | $ 41.47 |
| Average posted price for Berry's: | | | |
| Utah light crude oil | 56.34 | 53.03 | 38.60 |
| California 13 degree API heavy crude oil | 54.38 | 44.36 | 32.84 |
| Average crude price differential between WTI and Berry's: | | | |
| Utah light crude oil | 9.91 | 3.67 | 2.87 |
| California 13 degree API heavy crude oil | 11.87 | 12.34 | 8.63 |

The above posting prices and differentials are not necessarily amounts paid or received by us due to the contracts discussed below. While the crude oil price differential between WTI and California's heavy crude differential widened dramatically during 2004 and 2005, it was relatively stable in 2006. On December 31, 2006 the differential was $11.69 and ranged from a low of $11.39 to a high of $12.73 per barrel during the year. Crude oil price differentials between WTI and Utah's light crude oil were fairly consistent during 2004 and 2005 and were between $3 and $5 per barrel, but differentials widened considerably in 2006. On December 31, 2006 the differential was $13.75 and ranged from a low of $5.50 to a high of $13.75 per barrel during the year.

***Oil Contracts.*** We market our crude oil production to competing buyers including independent and major oil refining companies.

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

Prior to November 2005, we secured a three-year sales agreement, beginning in late 2002, with a major oil company whereby we sold over 90% of our California production under a negotiated pricing mechanism. This contract ended on January 31, 2006. Pricing in this agreement was based upon the higher of the average of the local field posted prices plus a fixed premium, or WTI minus a fixed differential near $6.00 per barrel. This contract allowed us to improve our California revenues over the posted price by approximately $41 million and $13 million in 2005 and 2004, respectively.

Utah - As of December 31, 2006, our Utah light crude oil is sold under multiple contracts with different purchasers for varying pricing terms and ranging from one month to nine months. As of December 31, 2006 we had firm contracts for 4,250 barrels per day (Bbl/D). These contracts are currently priced at approximately $13 to $20 per barrel below WTI with certain volumes tied to field posting, and in some cases our realized price is further reduced by transportation charges. As operator we deliver all produced volumes pursuant to these contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Our net volumes from our Brundage Canyon properties approximate 80% of the total gross volumes. Assuming all the Brundage Canyon wells are producing, the gross production could exceed these contracted volumes. We experienced increasing difficulty in locating additional buyers of our crude oil production from this region in 2006. Our Utah crude oil is a paraffinic crude, locally known as a black wax crude, and can be processed efficiently by only a limited number of refineries. Increased production of crude oil in the region, the ability of refiners to process other higher sulfur crudes as a result of capital upgrades, as well as the increasing availability of Canadian crude oil, is putting downward pressure on the sales price of our crude oil.

On February 27, 2007, we entered into a multi-staged crude oil sales contract with a subsidiary of Holly Corporation (Holly) for our Uinta basin crude oil. Under the agreement, Holly will begin purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in mid 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation, is a fixed percentage of WTI and approximates our expected field posted price of $13 to $16 below WTI. This contract provides the pricing assurance we need to proceed with the long-term development of our Uinta basin assets. From October 1, 2003 through April 30, 2006 we were able to sell our Utah crude oil at approximately $2.00 per barrel below WTI and from May 1, 2006 through September 30, 2006, we were selling the majority of our Utah crude at approximately $9.00 per barrel below WTI. Due to this lower pricing, and based on sales of 3,500 Bbl/D, our revenues were lower by approximately $9.2 million in 2006 as compared to 2005. If this pricing continues throughout 2007, with our Holly contract in place and on the same volumes, we estimate our revenues will be lower by approximately $8.6 million versus our 2006 revenues. We may adjust our capital expenditures in the Uinta basin due to various factors, including the timing of refinery demand for the Uinta barrels and the actual or expected change in our realized price.

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

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Annual average closing price per MMBtu for: | | | |
| NYMEX Henry Hub (HH) prompt month natural gas contract | $ 6.98 | $ 9.01 | $ 6.18 |
| Rocky Mountain Questar first-of-month indices (Brundage Canyon sales) | 5.36 | 6.73 | 5.05 |
| Rocky Mountain CIG first-of-month indices (Tri-State and Piceance sales) | 5.63 | 6.95 | 5.17 |
| Average natural gas price per MMBtu differential between NYMEX HH and: | | | |
| Questar | 1.86 | 2.28 | 1.13 |
| CIG | 1.60 | 2.06 | 1.01 |

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

***Firm Transportation Summary.***

| Name | From | To | Quantity (Avg. MMBtu/D) | Term | 2006 base costs per MMBtu | Remaining contractual obligation (in thousands) |
|---|---|---|---|---|---|---|
| Kern River Pipeline | Opal, WY | Kern County, CA | 12,000 | 5/2003 to 4/2013 | $ 0.643 | $ 17,826 |
| Rockies Express Pipeline | Piceance | Clarington, OH | 10,000 | 1/2008 to 12/2017 | 1.094(1) | 38,703 |
| Questar Pipeline | Brundage Canyon | Salt Lake City, UT | 2,500 | 9/2003 to 4/2012 | 0.174 | 846 |
| Questar Pipeline | Brundage Canyon | Salt Lake City, UT | 2,800 | 9/2003 to 9/2007 | 0.174 | 136 |
| KMIGT | Yuma County, CO | Grant, KS | 2,500 | 1/2005 to 10/2013 | 0.227 | 1,416 |
| Cheyenne Plains Gas Pipeline | Tri-State, CO | Panhandle Eastern Pipeline | 11,000 | 1/2007 to 12/2016 | 0.370 | 14,868 |
| Total | | | 40,800 | | | $ 73,795 |

*(1) We will experience lower rates from first in-service date until the pipeline is complete.*

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

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

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

**Steaming Operations.**

***Cogeneration Steam Supply.*** As of December 31, 2006, approximately 62% of our proved reserves, or 93 million barrels, consisted of heavy crude oil produced from depths of less than 2,000 feet. In pursuing our goal of being a cost-efficient heavy oil producer in California, we have consistently focused on minimizing our steam cost. We believe one of the main methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on our properties. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility, are located in our Midway-Sunset field. We also own a 42 MW cogeneration facility which is located in the Placerita field. Steam generation from these cogeneration facilities is more efficient than conventional steam generation as both steam and electricity are concurrently produced from a common fuel stream. By maintaining a correlation between electricity and natural gas prices, we are better able to control the cost of producing steam.

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

Total barrels of steam per day (BSPD) capacity as of December 31, 2006 is as follows:

| | |
|---|---|
| Total steam generation capacity of Cogeneration plants | 38,000 |
| Additional steam purchased under contract with a third party | 2,000 |
| Total steam generation capacity of conventional boilers | 67,000 |
| Total steam capacity | 107,000 |

The average volume of steam injected for the years ended December 31, 2006 and 2005 was 81,246 and 70,032 BSPD, respectively.

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

We are adding additional steam capacity for our development projects at Midway-Sunset, primarily diatomite, and Poso Creek to achieve maximum production from these properties. We regularly review our options to secure the most economical source for obtaining additional steam.

We operated most of our conventional steam generators in 2006 to achieve our goal of increasing heavy oil production. Approximately 65% of the volume of natural gas purchased to generate steam and electricity is based upon SoCal Border indices. We pay distribution/transportation charges for the delivery of gas to our various locations where we consume gas for steam generation purposes, however, in some cases this transportation cost is embedded in the price of gas. Approximately 26% of supply volume is purchased in Wyoming and moved to the Midway-Sunset field using our firm transportation capacity on the Kern River Pipeline. This gas is purchased based upon the Rocky Mountain Northwest Pipeline (NWPL) index. The remaining 9% of supply volume for the Poso Creek steaming operations is purchased based upon the PG&E Citygate index.

| | | 2006 | | 2005 | | 2004 |
|---|---|---|---|---|---|---|
| Average SoCal Border Monthly Index Price per MMBtu | $ | 6.29 | $ | 7.37 | $ | 5.60 |
| Average Rocky Mountain NWPL Monthly Index Price per MMBtu | | 5.66 | | 6.96 | | 5.24 |
| Average PG&E Citygate Monthly Index Price per MMBtu | | 6.70 | | 7.72 | | 5.85 |

We historically have been a net purchaser of natural gas, and thus our net income was negatively impacted when natural gas prices rose higher than its oil equivalent. In 2005, on a gas balance basis, we achieved parity due to our eastern Colorado (Tri-State) Niobrara gas acquisition. Thus, in 2006 and looking forward, we have been a net seller of gas and will benefit operationally when gas prices are higher. Increased production at Tri-State and the acquisition and development of the Piceance basin assets, which are all gas, has allowed us to improve our long natural gas position in 2006. The balance between natural gas consumed and produced during the fourth quarter ended December 31, 2006 was approximately as follows (MMBtu/D):

| | |
|---|---|
| Natural gas consumed in: | |
| Cogeneration operations | 27,000 |
| Conventional boilers | 18,000 |
| Total natural gas consumed | 45,000 |
| Less: Our estimate of approximate natural gas consumed to produce electricity (1) | (22,000) |
| Total approximate natural gas volumes consumed to produce steam | 23,000 |
| | |
| Natural gas produced: | |

| | |
|---|---|
| Tri-State (Niobrara) | 19,000 |
| Brundage Canyon (associated gas) | 15,000 |
| Piceance and other | 8,000 |
| Total natural gas volumes produced in operations | 42,000 |

*(1) We estimate this volume based on electricity revenues divided by the purchase price, including transportation, per MMBtu for the respective period.*

**Electricity.**

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

***Sales Contracts.*** Historically, we have sold electricity produced by our cogeneration facilities, each of which is a Qualifying Facility (QF) under the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA), to two California public utilities; Southern California Edison Company (Edison) and PG&E, under long-term contracts approved by the California Public Utilities Commission (CPUC). These contracts are referred to as standard offer (SO) contracts under which we are paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. An SO2 contract is more beneficial as it requires the utility to pay a higher capacity payment than an SO1contract. The SRAC energy price is currently determined by a formula approved by the CPUC that reflects the utility's marginal fuel cost and a conversion efficiency that represents a hypothetical resource to generate electricity in the absence of the cogenerator. During most periods natural gas is the marginal fuel for California utilities, so this formula provides a hedge against our cost of gas to produce electricity and steam in our cogeneration facilities. A proceeding is now underway at the CPUC to review and revise the methodology used to determine SRAC energy prices and to determine to what extent the utilities would be required to enter into further contracts with QFs. It is not known when the CPUC will issue a decision on SRAC pricing revisions. Also, there is no assurance that any new methodology will continue to provide a hedge against our fuel cost or that a revised pricing mechanism or terms will be as beneficial as the current contract pricing and terms.

The original SO2 contract for Placerita Unit 1 continues in effect through March 2009. This unit makes up approximately 6% of our total approximate barrels of steam per day (BSPD). The modified SRAC pricing terms of this contract reflected a fixed energy price of 5.37 cents/kilowatt hour (KWh) through June 2006, at which time the energy price reverted to the SRAC pricing methodology. We are paid a capacity payment that is fixed through the term of the contract.

In December 2004, we executed a five-year SO1 contract with Edison for the Placerita Unit 2 facility, and five-year SO1 contracts with PG&E for the Cogen 18 and Cogen 38 facilities, each effective January 1, 2005. Pursuant to these contracts, we are paid the purchasing utility's SRAC energy price and a capacity payment that is subject to adjustment from time to time by the CPUC. Edison and PG&E challenged, in the California Court of Appeals, the legality of the CPUC decision that ordered the utilities to enter into these five-year SO1 contracts, and similar one-year SO1 contracts that were ordered for 2004. The Court ruled that the CPUC had the right to order the utilities to execute these contracts. The Court also ruled that the CPUC was obligated to review the prices paid under the contracts and to adjust the prices retroactively to the extent it was later determined that such prices did not comply with the requirements of PURPA. To date, the CPUC has taken no final action based on this court ruling.

We believe that QFs, such as our facilities, provide an important source of distributive power generation into California's electricity grid, and as such, that our facilities will be economic to operate for at least the current five-year contract term. Based on the current pricing mechanism for our electricity under the contracts (which includes electricity purchased for internal use), we expect that our electricity revenues will be in the $45 million to $55 million range for 2007.

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. The facility also must meet certain energy efficiency standards. Each of our cogeneration facilities is a QF, pursuant to PURPA.

***Facility and Contract Summary.***

Purchaser

| Location and Facility | Type of Contract | | 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 (1) | 20 | - | 6,500 |
| Placerita Unit 2 | SO1 | Edison | Dec-09 | 16 | 4 | 6,500 |
| | | | | | | |
| Midway-Sunset | | | | | | |
| Cogen 18 | SO1 | PG&E | Dec-09 | 12 | 4 | 6,700 |
| Cogen 38 | SO1 | PG&E | Dec-09 | 37 | - | 18,000 |

*(1) On July 1, 2006, the contract pricing converted to the SRAC pricing of the original contract.*

**Competition.** The oil and gas industry is highly competitive. As an independent producer we have little control over the price we receive for our crude oil and natural gas. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to our customers. In acquisition activities, competition is intense as integrated and independent companies and individual producers are active bidders for desirable oil and gas properties and prospective acreage. Although many of these competitors have greater financial and other resources than we have, we believe we are in a position to compete effectively due to our business strengths (identified on page 4) and our determination to grow our business.

**Employees.** On December 31, 2006, we had 243 full-time employees, up from 209 full-time employees on December 31, 2005.

**Capital Expenditures Summary (Excluding Acquisitions).**

The following is a summary of the developmental capital expenditures incurred during 2006 and 2005 and budgeted capital expenditures for 2007 (in thousands):

| | 2007 (Budgeted) (1) | 2006 | 2005 |
|---|---|---|---|
| **CALIFORNIA** | | | |
| Midway-Sunset field | | | |
| New wells | $ 46,108 | $ 42,350 | $ 17,369 |
| Remedials/workovers | 2,355 | 2,261 | 1,079 |
| Facilities - oil & gas | 19,156 | 20,558 | 7,879 |
| Facilities - cogeneration | 55 | 415 | 3,053 |
| General | 1,875 | 479 | 1,271 |
| | 69,549 | 66,063 | 30,651 |
| Other California fields | | | |
| New wells | 10,270 | 8,641 | 6,965 |
| Remedials/workovers | 2,185 | 2,788 | 5,303 |
| Facilities - oil & gas | 5,230 | 6,599 | 3,677 |
| Facilities - cogeneration | 2,616 | 177 | 1,446 |
| General | 245 | 25 | 46 |
| | 20,546 | 18,230 | 17,437 |
| Total California | 90,095 | 84,293 | 48,088 |
| | | | |
| **ROCKY MOUNTAIN/MID-CONTINENT** | | | |
| Uinta Basin | | | |
| New wells | 34,689 | 103,183 | 50,354 |
| Remedials/workovers | - | 1,213 | 3,415 |
| Facilities | 3,098 | 5,966 | 1,860 |
| General | - | 1,072 | 4 |
| | 37,787 | 111,434 | 55,633 |
| Piceance Basin | | | |
| New wells | 94,534 | 36,654 | - |
| Facilities | 23,190 | 3,561 | - |
| | 117,724 | 40,215 | - |
| DJ Basin | | | |
| New wells/workovers | 12,241 | 19,468 | 11,257 |
| Remedials/workovers | 1,248 | 1,511 | 693 |
| Facilities | 5,151 | 7,883 | 2,569 |
| General | 366 | 427 | 387 |
| Land and seismic | 880 | - | - |
| | 19,886 | 29,289 | 14,906 |
| Williston Basin - New wells | - | 1,611 | - |
| Total Rocky Mountain and Mid-Continent | 175,397 | 182,549 | 70,539 |
| **Other Fixed Assets** | 2,000 | 19,574 | 647 |
| | | | |
| **TOTAL** | $ 267,492 | $ 286,416 | $ 119,274 |

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

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

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Net annual production: (1) | | | |
| Oil (Mbbl) | 7,182 | 7,081 | 7,044 |
| Gas (MMcf) | 12,526 | 7,919 | 2,839 |
| Total equivalent barrels (MBOE) (2) | 9,270 | 8,401 | 7,517 |
| | | | |
| Average sales price: | | | |
| Oil (per Bbl) before hedging | $ 52.92 | $ 47.04 | $ 33.43 |
| Oil (per Bbl) after hedging | 50.55 | 40.83 | 29.89 |
| Gas (per Mcf) before hedging | 5.48 | 7.88 | 6.13 |
| Gas (per Mcf) after hedging | 5.57 | 7.73 | 6.12 |
| Per BOE before hedging | 48.38 | 47.01 | 33.64 |
| Per BOE after hedging | 46.67 | 41.62 | 30.32 |
| Average operating cost - oil and gas production (per BOE) | 12.69 | 11.79 | 10.09 |

Mbbl - Thousands of barrels
MMcf - Million cubic feet
Bcf - Billion cubic feet
BOE - Barrels of oil equivalent
MBOE - Thousand barrels of oil equivalent
*(1) Net production represents that owned by us and produced to our interests.*
*(2) Equivalent oil and gas information is at a ratio of 6 thousand cubic feet (Mcf) of natural gas to 1 barrel (Bbl) of oil. A barrel of oil is equivalent to 42 U.S. gallons*

**Acreage and Wells.** As of December 31, 2006, our properties accounted for the following developed and undeveloped acres:

| | Developed Acres | | Undeveloped Acres | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| California | 7,559 | 7,559 | 7,038 | 7,038 | 14,597 | 14,597 |
| Colorado | 86,504 | 70,504 | 166,994 | 80,602 | 253,498 | 151,106 |
| Illinois | - | - | 6,161 | 5,552 | 6,161 | 5,552 |
| Kansas | - | - | 467,623 | 293,311 | 467,623 | 293,311 |
| Nebraska | - | - | 124,025 | 57,756 | 124,025 | 57,756 |
| North Dakota | - | - | 207,476 | 49,186 | 207,476 | 49,186 |
| Utah (1) (2) | 13,960 | 13,800 | 145,425 | 88,454 | 159,385 | 102,254 |
| Wyoming | 3,800 | 750 | 3,146 | 1,130 | 6,946 | 1,880 |
| Other | 80 | 19 | - | - | 80 | 19 |
| | 111,903 | 92,632 | 1,127,888 | 583,029 | 1,239,791 | 675,661 |

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

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

As of December 31, 2006, we have 3,050 gross productive wells (2,531 net). Gross wells represent the total number of wells in which we have a working interest. Net wells represent the number of gross wells multiplied by the percentages of the working interests owned by us. One or more completions in the same bore hole are counted as one well. Any well in which one of the multiple completions is an oil completion is classified as an oil well.

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

| | | 2006 | | 2005 | | 2004 |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Exploratory wells drilled (1): | | | | | | |
| Productive | 7 | 3 | 13 | 6 | 5 | 5 |
| Dry (2) | 5 | 1 | 1 | 1 | - | - |
| Development wells drilled: | | | | | | |
| Productive | 532 | 356 | 213 | 176 | 123 | 111 |
| Dry (2) | 7 | 5 | 7 | 5 | - | - |
| Total wells drilled: | | | | | | |
| Productive | 539 | 359 | 226 | 182 | 128 | 116 |
| Dry (2) | 12 | 6 | 8 | 6 | - | - |

*(1) 2005 does not include one gross well drilled by our industry partner that was being evaluated at December 31, 2005.*
*(2) 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.*

| | | 2006 |
|---|---|---|
| | Gross | Net |
| Total productive wells drilled: | | |
| Oil | 258 | 254 |
| Gas | 281 | 105 |

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

***Company Owned Drilling Rigs***. During 2005 and 2006, we purchased three drilling rigs, two of which are operational. Our third rig is being refurbished and is scheduled to begin drilling in the Piceance in 2007. Owning these rigs allows us to successfully meet a portion of our drilling needs in the Uinta and Piceance basins. See Note 10 to the financial statements.

***Other.*** At year-end, we had no subsidiaries, no special purpose entities and no off-balance sheet debt. We did not enter into any material related party transactions in 2006.

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

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

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

***Regulation of oil and gas.*** The oil and gas industry, including our operations, is extensively regulated by numerous federal, state and local authorities, and with respect to tribal lands, Native American tribes.

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

***Federal energy regulation.*** The enactment of PURPA, as amended, and the adoption of regulations thereunder by the Federal Energy Regulatory Commission (FERC) provided incentives for the development of cogeneration facilities such as ours. A domestic electricity generating project must be a QF under FERC regulations in order to benefit from certain rate and regulatory incentives provided by PURPA.

PURPA provides two primary benefits to QFs. First, QFs generally are relieved of compliance with extensive federal and state regulations that control the financial structure of an electricity generating plant and the prices and terms on which electricity may be sold by the plant. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost, and that the utility sell back-up power to the QF on a non-discriminatory basis. The term "avoided cost" is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. The Energy Policy Act of 2005 amends PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if the FERC determines that a competitive wholesale electricity market is available to QFs in its service territory. Such a determination has not been made for our service areas in California. This amendment does not affect any of our current SO contracts. FERC issued an order on October 20, 2006 implementing this amendment to PURPA and on December 20, 2006 issued a subsequent order granting limited rehearing of the October 20, 2006 order. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utilities' avoided costs.

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

## Forward Looking Statements

“Safe harbor under the Private Securities Litigation Reform Act of 1995:” Any statements in this Form 10-K that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as “will,” “might,” “intend,” “continue,” “target(s),” “expect,” “achieve,” “strategy,” “future,” “may,” “could,” “goal(s),”, “forecast,” “anticipate,” or other words or phrases, or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management’s current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 15 of this Form 10-K filed with the Securities and Exchange Commission, under the heading “Risk Factors.”

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## Item 1A. Risk Factors

### Other Factors Affecting the Company's Business and Financial Results

***Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business, results of operations and financial condition.*** Our revenues, profitability and future growth and reserve calculations depend substantially on reasonable prices for oil and gas. These prices also affect the amount of our cash flow available for capital expenditures, working capital and payments on our debt and our ability to borrow and raise additional capital. The amount we can borrow under our senior unsecured revolving credit facility (see Note 6 to the financial statements) is subject to periodic asset redeterminations based in part on changing expectations of future crude oil and natural gas prices. Lower prices may also reduce the amount of oil and gas that we can produce economically.

Among the factors that can cause fluctuations are:

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

We have multiple hedges placed on our oil and gas production. See Item 7A Quantitative and Qualitative Disclosures About Market Risk.

***Our heavy crude in California is less economic than lighter crude oil and natural gas.*** As of December 31, 2006, approximately 66% of our proved reserves, or 99 million barrels, consisted of heavy oil. Light crude oil represented 9% and natural gas represented 25% of our oil and gas reserves. Heavy crude oil sells for a discount to light crude oil, as more complex refining equipment is required to convert heavy oil into high value products. We currently sell our heavy crude oil in California under a long-term contract for approximately $8.15 below WTI NYMEX, the U.S. benchmark crude oil, pricing. Additionally, most of our crude oil in California is produced using the enhanced oil recovery process of steam injection. This process is more costly than primary and secondary recovery methods.

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

***A widening of commodity differentials may adversely impact our revenues and per barrel economics.*** Both our produced crude oil and natural gas are subject to pricing in the local markets where the production occurs. It is customary that such products are priced based on local or regional supply and demand factors. California heavy crude oil sells at a discount to WTI, primarily due to the additional cost to refine gasoline or light product out of a barrel of heavy crude. In addition, our Utah light crude contracts are currently priced at approximately $13 to $20 per barrel below WTI with certain volumes tied to field posting, and in some cases our realized price is further reduced by transportation charges. Natural gas field prices are normally priced off of Henry Hub NYMEX price, the benchmark for U.S. natural gas. While we attempt to contract for the best possible price in each of our producing locations, there is no assurance that past price differentials will continue into the future. Numerous factors may influence local pricing, such as refinery capacity, particularly for paraffinic crude, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be adversely impacted by a widening differential on the products we sell. Our oil and natural gas hedges are based on WTI or natural gas index prices, so we may be subject to basis risk if the differential on the products we sell widens from those benchmarks if we do not have a contract tied to those benchmarks. Additionally, insufficient pipeline capacity and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and gas producing areas.

***Market conditions or operational impediments may hinder our access to crude oil and natural gas markets or delay our production.*** Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and refineries owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of natural gas pipelines, gathering system capacity, processing facilities or refineries. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market. See firm transportation summary schedule at Item 1 Business.

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

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

Utah - As of December 31, 2006, our Utah light crude oil is sold under multiple contracts with different purchasers for varying pricing terms and ranging from one month to nine months. As of December 31, 2006 we had firm contracts for 4,250 barrels per day (Bbl/D). These contracts are currently priced at approximately $13 to $20 per barrel below WTI with certain volumes tied to field posting, and in some cases our realized price is further reduced by transportation charges. As operator we deliver all produced volumes pursuant to these contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Our net volumes from our Brundage Canyon properties approximate 80% of the total gross volumes. Assuming all the Brundage Canyon wells are producing, the gross production could exceed these contracted volumes. We experienced increasing difficulty in locating additional buyers of our crude oil production from this region in 2006. Our Utah crude oil is a paraffinic crude, locally known as a black wax crude, and can be processed efficiently by only a limited number of refineries. Increased production of crude oil in the region, the ability of refiners to process other higher sulfur crudes as a result of capital upgrades, as well as the increasing availability of Canadian crude oil, is putting downward pressure on the sales price of our crude oil.

On February 27, 2007, we entered into a multi-staged crude oil sales contract with a subsidiary of Holly Corporation (Holly) for our Uinta basin crude oil. Under the agreement, Holly will begin purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in mid 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation, is a fixed percentage of WTI and approximates our expected field posted price of $13 to $16 below WTI. From October 1, 2003 through April 30, 2006 we were able to sell our Utah crude oil at approximately $2.00 per barrel below WTI and from May 1, 2006 through September 30, 2006, we were selling the majority of our Utah crude at approximately $9.00 per barrel below WTI. Due to this lower pricing, and based on sales of 3,500 Bbl/D, our revenues were lower by approximately $9.2 million in 2006 as compared to 2005. If this pricing continues throughout 2007, with our Holly contract in place and on the same volumes, we estimate our revenues will be lower by approximately $8.6 million versus our 2006 revenues. We may adjust our capital expenditures in the Uinta basin due to various factors, including the timing of refinery demand for the Uinta barrels and the actual or expected change in our realized price.

***We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly.*** We are dependent on several cogeneration facilities that, combined, provide approximately 40% of our steam requirement. These facilities are dependent on reasonable power contracts for the sale of electricity. If, for any reason, including if utilities that purchase electricity from us are no longer required by regulation to enter into power contracts with us, we were unable to enter into new or replacement contracts or were to lose any existing contract, we may not be able to supply 100% of the steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements. The financial cost and timing of such new investment may adversely affect our production, capital outlays and cash provided by operating activities. We have power contracts covering our electricity generation which contracts expire in 2009.

***The future of the electricity market in California is uncertain.*** We utilize cogeneration plants in California to generate lower cost steam compared to conventional steam generation methods. Electricity produced by our cogeneration plants is sold to utilities and the steam costs are allocated to our oil and gas operations. While we have electricity sales contracts in place with the utilities that are currently scheduled to terminate in 2009, legal and regulatory decisions, (especially related to the pricing of electricity under the contracts), can adversely affect the economics of our cogeneration facilities and thereby, the cost of steam for use in our oil and gas operations.

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

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

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

***Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves , future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates.*** Estimating accumulations of oil and gas is complex. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC. The accuracy of a reserve estimate is a function of:

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

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

In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

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

We capitalize costs to acquire, find and develop our oil and gas properties under the successful efforts accounting method. If net capitalized costs of our oil and gas properties exceed fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties annually and at any time when events or circumstances indicate a review is necessary, based on prices in effect as of the end of the reporting period. The carrying value of oil and gas properties is computed on a field-by-field basis. Once incurred, a writedown of oil and gas properties is not reversible at a later date even if oil or gas prices increase. See Item 7A Quantitative and Qualitative Disclosures About Market Risk for our hedge position on February 9, 2007.

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

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

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

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

- fires;
- explosions;
- blow-outs;
- uncontrollable flows of oil, gas, formation water or drilling fluids;
- natural disasters;
- pipe or cement failures;
- casing collapses;
- embedded oilfield drilling and service tools;
- abnormally pressured formations;
- major equipment failures, including cogeneration facilities; and
- environmental hazards such as oil spills, natural gas leaks, pipeline ruptures and discharges of toxic gases.

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

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

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

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

In addition, we could also be liable for the investigation or remediation of contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage. Such liabilities may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate, and may arise even where the contamination does not result from any noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. We have incurred expenses and penalties in connection with remediation of contamination in the past, and we may do so in the future. From time to time we have experienced accidental spills, leaks and other discharges of contaminants at some of our properties, as have other similarly situated oil and gas companies. Some of the properties that we have acquired, or in which we may hold an interest but not operational control, may have past or ongoing contamination for which we may be held responsible. Some of our operations are in environmentally sensitive areas, including coastal areas, wetlands, areas that may provide habitat for endangered or threatened species, and other protected areas, and our operations in such areas must satisfy additional regulatory requirements. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed certain drilling projects and/or access to prospective lands and have filed litigation to attempt to stop such projects, including decisions by the Bureau of Land Management regarding several leases in Utah that we have been awarded.

Our activities are also subject to the regulation by oil and natural gas-producing states and one Native American tribe of conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from federal, state, local and Native American tribal authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions that are more expensive than we have anticipated could have a negative effect on our ability to explore on or develop our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

Recent and future environmental regulations, including additional state and federal restrictions on greenhouse gasses that may be passed in response to climate change concerns, could increase our costs to operate and produce our properties and also reduce the demand for the oil and gas we produce. On September 27, 2006, California’s governor signed into law Assembly Bill (AB) 32, which establishes a statewide cap on greenhouse gases (GHG) for 2020 based on 1990 emission levels. The California Air Resources Board (CARB) has been designated as the lead agency to establish and adopt regulations to implement AB 32 (GHG Regulations) by January 1, 2012. We will continue to monitor the establishment of GHG Regulations through industry trade groups and other organizations in which we are a member. While California’s GHG Regulations apply only to operations within California, similar regulations may be adopted in other states in which we conduct business or on a Federal level in the future.

Furthermore, we benefit from federal energy laws and regulations that relieve our cogeneration plants, all of which are QFs, from compliance with extensive federal and state regulations that control the financial structure of electricity generating plants, as well as the prices and terms on which electricity may be sold by those plants. These federal energy regulations also require that electric utilities purchase electricity generated by our cogeneration plants at a price based on the purchasing utility's avoided cost, and that the utility sell back-up power to us on a non-discriminatory basis. The term "avoided cost" is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. The Energy Policy Act of 2005 amends PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if the FERC determines that a competitive wholesale electricity market is available to QFs in its service territory. Such a determination has not been made for our service areas in California. This amendment does not affect any of our current SO contracts. FERC issued an order on October 20, 2006 implementing this amendment to PURPA and on December 20, 2006 issued a subsequent order granting limited rehearing of the October 20, 2006 order. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utilities' avoided costs.

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

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

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

***There are risks in acquiring producing properties, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of management attention, and costs of increased scope, geographic diversity and complexity of our operations.*** Increasing our reserve base through acquisitions is an important part of our business strategy. Our failure to integrate acquired businesses successfully into our existing business, or the expense incurred in consummating future acquisitions, could result in our incurring unanticipated expenses and losses. In addition, we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

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

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

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

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

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

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

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties and rig availability and access to our drilling locations utilizing available roads. As of December 31, 2006, we own three drilling rigs, one of which is drilling on our property, and have additional one-year contract commitments on another three drilling rigs. See contractual obligations in Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operation.

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

## Item 1B. Unresolved Staff Comments

None.

## Item 2. Properties

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

## Item 3. Legal Proceedings

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

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

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

**Executive Officers.** Listed below are the names, ages (as of December 31, 2006) and positions of our executive officers and their business experience during at least the past five years. All our officers are reappointed in May of each year at an organizational meeting of the Board of Directors. There are no family relationships between any of the executive officers and members of the Board of Directors.

ROBERT F. HEINEMANN, 53, 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 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, 50, 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.

MICHAEL DUGINSKI, 40, has been Executive Vice President of Corporate Development and California since October 2005. Mr. Duginski was Senior Vice President of Corporate Development from June 2004 through October 2005 and was Vice President of Corporate Development from February 2002 through June 2004. Mr. Duginski, a mechanical engineer, was previously with Texaco, Inc. from 1988 to 2002 where his positions included Director of New Business Development, Production Manager and Gas and Power Operations Manager. Mr. Duginski is also an Assistant Secretary.

DAN ANDERSON, 44, has been Vice President of Rocky Mountain/Mid-Continent Production since October 2005. Mr. Anderson was Rocky Mountain/Mid-Continent Manager of Engineering from August 2003 through October 2005. Mr. Anderson was previously a Senior Staff Petroleum Engineer with Williams Production RMT from August 2001 through August 2003. He previously was a Senior Staff Engineer with Barrett Resources from October 2000 through August 2001.

WALTER B. AYERS, 63, has been Vice President of Human Resources since May 2006. Mr. Ayers was previously a private consultant to the energy industry from January 2002 until his employment with us. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000 where his positions included Manager of Compensation and various other human resource management positions primarily in the upstream sector of Mobil.

GEORGE T. CRAWFORD, 46, has been Vice President of California Production since October 2005. Mr. Crawford was Vice President of Production from December 2000 through October 2005 and was Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, previously served as the Production Engineering Supervisor for Atlantic Richfield Corp. (ARCO) from 1989 to 1998 in numerous engineering and operational assignments including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

BRUCE S. KELSO, 51, has been Vice President of Rocky Mountain/Mid-Continent Exploration since October 2005. Mr. Kelso was Rocky Mountain/Mid-Continent Exploration Manager from August 2003 through October 2005. Mr. Kelso, a petroleum geologist, was previously a Senior Staff Geologist assigned to Rocky Mountain assets with Williams Production RMT, from January 2002 through August 2003. He previously held the position of Vice President of Exploration and Development at Redstone Resources, Inc. from 2000 to 2001.

SHAWN M. CANADAY, 31, 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 Chevron and in public accounting. Mr. Canaday is presently an Assistant Secretary. Effective March 2, 2007, Mr. Canaday will replace Mr. Wilson as Controller.

KENNETH A. OLSON, 51, has been Corporate Secretary since December 1985 and was Treasurer from August 1988 until December 2004.

STEVEN B. WILSON, 43, has been Controller since January 2007. Mr. Wilson had been Assistant Controller since November 2003 and before joining us in November 2003, served as the vice president of finance and administration for Accela, Inc., a software development company, for three years. Prior to that, he held finance functions in select companies and in public accounting. Effective March 2, 2007, Mr. Wilson will replace Mr. Canaday as Treasurer and will also be an Assistant Secretary.

## 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 $.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Common Stock at the option of the holder.

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

Our Class A Common Stock is listed on the New York Stock Exchange (NYSE) under the symbol BRY. The Class B Stock is not publicly traded. The market data and dividends for 2006 and 2005 are shown below:

| | | 2006 | | | 2005 | |
|---|---|---|---|---|---|---|
| | | Price Range | | | Price Range | |
| | High | Low | Dividends Per Share | High (1) | Low (1) | Dividends Per Share (1) |
| First Quarter | $ 39.98 | $ 28.60 | $ .065 | $ 33.05 | $ 21.93 | $ .060 |
| Second Quarter | 39.00 | 27.27 | .065 | 27.48 | 20.39 | .060 |
| Third Quarter | 35.77 | 26.07 | .095 | 33.50 | 26.15 | .115 |
| Fourth Quarter | 33.69 | 25.71 | .075 | 34.33 | 26.15 | .065 |
| Total Dividend Paid | | | $ .300 | | | $ .300 |

| | February 9, 2007 | December 31, 2006 | December 31, 2005 (1) |
|---|---|---|---|
| Berry's Common Stock closing price per share as reported on NYSE Composite Transaction Reporting System | $ 30.55 | $ 31.01 | $ 28.60 |

*(1) The 2005 amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.*

The number of holders of record of our Common Stock was 543 as of February 9, 2007. There was one Class B Shareholder of record as of February 9, 2007.

***Dividends.*** We paid a special dividend of $.02 per share on September 29, 2006 and increased our regular quarterly dividend by 15%, from $.065 to $.075 per share beginning with the September 2006 dividend. Our regular annual dividend is currently $.30 per share, payable quarterly in March, June, September and December. We paid a special dividend of $.05 per share on September 29, 2005 and increased our regular quarterly dividend by 8%, from $.06 to $.065 per share beginning with the September 2005 dividend.

Since our formation in 1985 through December 31, 2006, we have paid dividends on our Common Stock for 69 consecutive quarters and previous to that for eight consecutive semi-annual periods. We intend to continue the payment of dividends, although future dividend payments will depend upon our level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors. Dividend payments are limited by covenants in our 1) credit facility to the greater of $20 million or 75% of net income, and 2) bond indenture of up to $20 million annually irrespective of our coverage ratio or net income and up to $10 million in the event we are in a non-payment default.

As of December 31, 2006, dividends declared on 7,793,080 shares of certain Common Stock are restricted, whereby we pay 37.5% of the dividends declared on these shares to the surviving member of a group of individuals, the B group, for as long as this remaining member shall live.

***Equity Compensation Plan Information.***

| Plan category | Number of securities to be issued upon exercise of outstanding options, warrants and rights | Weighted average exercise price of outstanding options, warrants and rights | Number of securities remaining available for future issuance |
|---|---|---|---|
| Equity compensation plans approved by security holders | 3,318,991 | $20.97 | 1,252,344 |
| Equity compensation plans not approved by security holders | none | none | none |

***Issuer Purchases of Equity Securities.***

In June 2005, we announced that our Board of Directors authorized a share repurchase program for up to an aggregate of $50 million of our outstanding Class A Common Stock. From June 2005 through December 31, 2006, we have purchased 818,000 shares in the open market for approximately $25 million. In 2006, our repurchases increased diluted earnings by $.03 per share.

In December 2005, we adopted a plan under Rule 10b5-1 of the Securities Exchange Act of 1934 to facilitate the repurchase of our shares of common stock. Rule 10b5-1 allows a company to purchase its shares at times when it would not normally be in the market due to possession of nonpublic information, such as the time immediately preceding its quarterly earnings releases. This plan expired on December 1, 2006. This 10b5-1 plan was authorized under, and administered consistent with, our $50 million share repurchase program. We may repurchase shares in the open market from time to time during our normal trading windows or under a new plan under 10b5-1. All repurchases of common stock are made in compliance with regulations set forth by the SEC and are subject to market conditions, applicable legal requirements and to other factors.

This share repurchase program does not obligate us to acquire any particular amount of common stock and the plan may be suspended at any time at our discretion.

| Period | Total number of shares purchased | Average price paid per share | Total number of shares purchased as part of publicly announced plans or programs | Maximum number (or approximate dollar value) of shares that may yet be purchased under the plans or programs |
|---|---|---|---|---|
| Fiscal Year 2005 (1) | 217,800 | $ 29.00 | 217,800 | $ 43,684,500 |
| First Quarter 2006 | 60,000 | 30.04 | 60,000 | 41,882,036 |
| Second Quarter 2006 | 347,700 | 31.55 | 347,700 | 30,912,780 |
| Third Quarter 2006 | 92,500 | 32.37 | 92,500 | 27,918,703 |
| October 2006 | 100,000 | 29.48 | 100,000 | 24,971,116 |
| Total | 818,000 | $ 30.60 | 818,000 | $ 24,971,116 |

*(1) The 2005 share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.*

**Performance Graph**

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

Total returns assume $100 invested on December 31, 2001 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index (S&P 500) and two Peer Groups, assuming reinvestment of dividends for each measurement period. In the proxy statement filed in 2006, we added Peer Group 1, which contains 10 companies, which we used for comparisons that year, and in this Form 10-K we added Peer Group 2. We believe Peer Group 2 is a better comparison index for our performance graph based on similar types of assets and market capitalization.

We intend to discontinue the use Peer Group 1 after this year's report on Form 10-K. The information shown is historical and is not necessarily indicative of future performance. The ten companies which make up Peer Group 1 are as follows: Bill Barrett Corp. (publicly traded since December 10, 2004), Cabot Oil & Gas Corp., Cimarex Energy Co. (publicly traded since September 30, 2002), Comstock Resources Inc., Denbury Resources Inc., Encore Acquisition Co. (publicly traded since March 9, 2001), Energy Partners Ltd., Range Resources Corp., St. Mary Land & Exploration Co. and Whiting Petroleum Corp. (publicly traded since November 20, 2003).

The 16 companies which make up Peer Group 2 (to be used going forward) are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Encore Acquisition Co., Forest Oil Corp., Houston Exploration Co., Petrohawk Energy Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Range Resources Corp., St. Mary Land & Exploration Co., Stone Energy Corp., Swift Energy Co., Whiting Petroleum Corp.

| | 12/01 | 12/02 | 12/03 | 12/04 | 12/05 | 12/06 |
|---|---|---|---|---|---|---|
| Berry Petroleum Company | 100.00 | 111.30 | 135.80 | 325.26 | 393.93 | 431.40 |
| S & P 500 | 100.00 | 77.90 | 100.24 | 111.15 | 116.61 | 135.03 |
| Russell 2000 | 100.00 | 79.52 | 117.09 | 138.55 | 144.86 | 171.47 |
| Peer Group 1 | 100.00 | 125.10 | 172.17 | 267.33 | 393.25 | 402.45 |
| Peer Group 2 | 100.00 | 101.28 | 133.38 | 202.06 | 291.67 | 294.64 |

**Item 6. Selected Financial Data**

The following table sets forth certain financial information and is qualified in its entirety by reference to the historical financial statements and notes thereto included in Item 8 Financial Statements and Supplementary Data. The statement of income and balance sheet data included in this table for each of the five years in the period ended December 31, 2006 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data).

| | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| **Audited Financial Information** | | | | | |
| *Statement of Income Data*: | | | | | |
| Sales of oil and gas | $ 430,197 | $ 349,691 | $ 226,876 | $ 135,848 | $ 102,026 |
| Sales of electricity | 52,932 | 55,230 | 47,644 | 44,200 | 27,691 |
| Operating costs - oil and gas production | 117,624 | 99,066 | 73,838 | 57,830 | 41,108 |
| Operating costs - electricity generation | 48,281 | 55,086 | 46,191 | 42,351 | 26,747 |
| Production taxes | 14,674 | 11,506 | 6,431 | 3,097 | 2,907 |
| General and administrative expenses (G&A) | 36,841 | 21,396 | 22,504 | 14,495 | 10,417 |
| Depreciation, depletion & amortization (DD&A) | | | | | |
| Oil and gas production | 67,668 | 38,150 | 29,752 | 17,258 | 13,388 |
| Electricity generation | 3,343 | 3,260 | 3,490 | 3,256 | 3,064 |
| Net income | 107,943 | 112,356 | 69,187 | 32,363 | 29,210 |
| Basic net income per share (1) | 2.46 | 2.55 | 1.58 | .74 | .67 |
| Diluted net income per share (1) | 2.41 | 2.50 | 1.54 | .73 | .67 |
| Weighted average number of shares outstanding (basic) (1) | 43,948 | 44,082 | 43,788 | 43,544 | 43,482 |
| Weighted average number of shares outstanding (diluted) (1) | 44,774 | 44,980 | 44,940 | 44,062 | 43,804 |
| *Balance Sheet Data*: | | | | | |
| Working capital | $ (100,594) | $ (54,757) | $ (3,840) | $ (3,540) | $ (2,892) |
| Total assets | 1,198,997 | 635,051 | 412,104 | 340,377 | 259,325 |
| Long-term debt | 390,000 | 75,000 | 28,000 | 50,000 | 15,000 |
| Shareholders' equity | 427,700 | 334,210 | 263,086 | 197,338 | 172,774 |
| Cash dividends per share (1) | .30 | .30 | .26 | .24 | .20 |
| *Operating Data*: | | | | | |
| Cash flow from operations | 243,229 | 187,780 | 124,613 | 64,825 | 57,895 |
| Exploration and development of oil and gas properties | 265,110 | 118,718 | 71,556 | 41,061 | 30,163 |
| Property/facility acquisitions | 257,840 | 112,249 | 2,845 | 48,579 | 5,880 |
| Additions to vehicles, drilling rigs and other fixed assets | 21,306 | 11,762 | 669 | 494 | 469 |
| **Unaudited Operating Data** | | | | | |
| *Oil and gas producing operations (per BOE):* | | | | | |
| Average sales price before hedging | $ 48.38 | $ 47.01 | $ 33.64 | $ 24.48 | $ 20.11 |
| Average sales price after hedging | 46.67 | 41.62 | 30.32 | 22.52 | 19.39 |
| Average operating costs - oil and gas production | 12.69 | 11.79 | 10.09 | 9.57 | 7.83 |
| Production taxes | 1.58 | 1.37 | .86 | .51 | .55 |
| G&A | 3.98 | 2.55 | 2.99 | 2.40 | 1.98 |
| DD&A - oil and gas production | 7.30 | 4.54 | 3.96 | 2.86 | 2.55 |
| | | | | | |
| *Production* (MBOE) | 9,270 | 8,401 | 7,517 | 6,040 | 5,251 |
| *Production* (MMWh) | 757 | 741 | 776 | 767 | 748 |
| *Proved Reserves Information:* | | | | | |
| Total BOE | 150,262 | 126,285 | 109,836 | 109,920 | 101,719 |

| | | | | | |
|---|---|---|---|---|---|
| Standardized measure (2) | $ 1,182,268 | $ 1,251,380 | $ 686,748 | $ 528,220 | $ 449,857 |
| Year-end average BOE price for PV10 purposes | 41.23 | 48.21 | 29.87 | 25.89 | 24.91 |
| *Other:* | | | | | |
| Return on average shareholders' equity | 28.33% | 37.63% | 31.06% | 17.50% | 17.90% |
| Return on average capital employed | 18.21% | 32.74% | 26.29% | 15.44% | 16.42% |

*(1) All earnings per share and share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.*

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

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

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

- Developing our existing resource base
- Acquiring additional assets with significant growth potential
- Utilizing joint ventures with respected partners to enter new basins
- Accumulating significant acreage positions near our producing operations
- Investing our capital in a disciplined manner and maintaining a strong financial position

**Notable Items in 2006.**

- Achieved record production which averaged 25,398 BOE/D, up 10% from 2005
- Achieved record cash from operating activities of $243 million, up 29% from 2005
- Achieved net income of $108 million, down 4% from 2005
- Added 33.4 million BOE of proved reserves before production ending 2006 at 150.3 million BOE
- Achieved reserve replacement rate of 359%
- Expended $554 million of capital expenditures, including $286 million of developmental capital expenditures
- Acquired operatorship and 50% working interest in 6,300 gross acres of natural gas assets in the Garden Gulch property in the Grand Valley field in the Piceance basin, Colorado, at an acquisition cost of $159 million
- Entered into an agreement to jointly develop natural gas properties in the North Parachute Ranch property in the Grand Valley field in the Piceance basin, Colorado, to earn a 95% working interest in 4,300 gross acres near our Garden Gulch assets
- Announced development of our diatomite asset (heavy oil) with a 100 well drilling program scheduled for 2007 in the Midway-Sunset field, California
- Discovered light oil accumulations in the Green River and Wasatch formations at Lake Canyon, Uinta basin, Utah
- Added financial capacity by increasing our senior unsecured revolving credit facility to $750 million with an initial borrowing base of $500 million
- Issued $200 million of ten year 8.25% senior subordinated notes in October 2006
- Completed two-for-one split of Class A Common Stock and Class B Stock
- Increased our regular quarterly dividend by 15% to $.075 per share ($.30 annually) and declared a special dividend of $.02 per share

***Notable Items and Expectations for 2007.***

- Expecting 2007 developmental capital expenditures to approximate $227 million to $267 million
- Targeting a 20% to 25% increase in 2007 year end proved reserves, or 175 to 185 MMBOE
- Beginning major development of our Piceance assets with over 55 to 65 wells planned
- Targeting net average production of between 27,000 and 28,000 BOE/D
- Entered into a long-term crude oil sales contract for our Uinta basin, Utah production
- Potential divestiture of non-strategic assets to focus on our large resource development opportunities

***Overview of the Fourth Quarter of 2006.*** We achieved record production of 26,887 BOE/D even though we reduced production in the Uinta basin (estimated impact to the fourth quarter of 2006 was approximately 2,000 Bbl/D) due to an unscheduled refinery shutdown. The refinery resumed operations in mid-January 2007. Our price differential for our black wax crude oil in the Uinta basin widened causing lower realizations and negatively impacted our earnings for the quarter. Improving the demand for this crude has been a major challenge. This situation, and generally weaker oil and gas prices, lowered our realized prices by 11% compared to the third quarter of 2006.

***View to 2007.*** Our challenge for 2007 is to manage our business in a rapidly changing price and operating environment while adding significant reserves through the drill bit. We have an extensive inventory of development drilling in several basins, and expect our program to be the most influenced by production and reserve growth in the Piceance basin. We intend our capital program, excluding acquisitions, to closely reflect our cash flow from operations. Additional funds may be provided by the divestiture of several non-strategic assets, including our Montalvo properties, Bakken acreage and others. We have six asset teams, three in California and three in the Rocky Mountain/Mid-Continent region, and each team has specific targets on production, reserve growth, capital expenditures and operating costs. We believe managing our assets in this manner will maximize operational efficiencies and add the most value to our shareholders. We will manage our balance sheet prudently, and while we are focused on the continuing development of our existing assets, we will continue to evaluate acquisition opportunities that fit our growth strategy.

***View to the First Quarter of 2007.*** Crude oil prices (WTI) were volatile in the first quarter ranging from $50.48 per barrel WTI to $61.39 per barrel and we expect oil and gas prices to remain volatile in 2007. On February 27, 2007 we entered into a long-term (six year) crude oil sales contract for our Uinta basin production. This contract will allow us to improve our margins on these barrels beginning on July 1, 2007 and provides us assurance of deliverability and return on our investment. We are accelerating our investment in our Poso Creek, California properties due to its excellent response to our 2006 development activity. Our total net production volumes in the first quarter are expected to average between 24,000 and 26,000 BOE/D.

***Piceance Basin - Our New Core Area***. In 2006, we made two separate significant investments in the gas rich Piceance basin in Colorado, targeting the Williams Fork section of the Mesaverde formation. We spent $312 million (balance of $54 million due in 2007) to acquire a high working interest in several prime blocks of acreage located in the Grand Valley field. Most of the acreage was undeveloped and we added only 4.3 MMBOE in proved reserves from these acquisitions. We believe we have accumulated a very sizable resource base which will allow us to add significant proved reserves over the next five years. We believe we have over 1,000 drilling locations on this acreage. We are anticipating initial gross production ranging from 1.3 to 2.0 MMcf per well with the ultimate risked gross recovery of approximately 1.5 Bcf per well. Well costs are expected to be in the $1.8 million to $2.5 million range per well and we are targeting average depths of between 10,000 feet to 12,000 feet. We anticipate running four rigs in 2007 to develop this asset.

***Capital expenditures.*** Our capital expenditures for 2006 totaled $553 million consisting of $258 million for acquisitions, $265 million for exploration and development, $21 million for drilling rigs and other assets and $9 million of capitalized interest. We funded these items from $243 million of operating cash flow and $310 million from additional borrowings. This compares to our total capital expenditures in 2005 of $243 million, which consisted of $112 million of acquisitions, $119 million in exploration and development and $12 million in drilling rigs and other assets.

Excluding the acquisition price of new properties, in 2007 we have a developmental capital program of approximately $267 million and we will make a final payment of $54 million associated with our Piceance joint venture. We are proceeding with this program, but may revise our plans due to lower commodity price expectations, to the timing of crude deliveries out of the Uinta basin, to equipment availability, to permitting or other factors.

Our 2007 capital program allows us to continue high activity levels and as a result, we are targeting 2007 production to average between 27,000 BOE/D to 28,000 BOE/D. In 2007, we expect production to be approximately 62% heavy oil, 11% light oil and 27% natural gas and anticipate funding our development capital program primarily from internally generated cash flow. We have currently secured the necessary equipment and are meeting permit requirements to achieve the 2007 program.

**Development, Exploitation and Exploration Activity**. We drilled 568 gross (382 net) wells during 2006, realizing a gross success rate of 98 percent. Excluding any future acquisitions, our targeted 2007 developmental capital budget is $267 million. As of December 31, 2006, we have four rigs drilling on our properties under long-term contracts and have several more rigs scheduled to begin in early 2007.

***Drilling Activity.*** The following table sets forth certain information regarding drilling activities for the year ended December 31, 2006:

| | Gross Wells | Net Wells |
|---|---|---|
| SMWSS | 50 | 50 |

| | | |
|---|---|---|
| NMWSS | 81 | 80 |
| Socal *(1)* | 38 | 38 |
| Piceance | 68 | 11 |
| Uinta *(2)* | 108 | 106 |
| DJ *(3)* | 223 | 97 |
| **Totals** | **568** | **382** |

*(1) Includes 1 gross well (1 net well) that was a dry hole at North Midway-Sunset.*

*(2) Includes 2 gross wells (2 net wells) that were dry holes at Coyote Flats.*

*(3) Includes 5 gross wells (2.4 net wells) that were dry holes in Tri-State and 4 gross wells (.3 net well) that were dry holes in Bakken.*

**Net Oil and Gas Producing Properties at December 31, 2006.**

| Name, State | % Average Working Interest | Total Net Acres | Proved Reserves (BOE) in thousands | Proved Developed Reserves (BOE) in thousands | % of Total Proved Reserves | Proved Undeveloped Reserves (BOE) in thousands | % of Total Proved Reserves | Average Depth of Producing Reservoir (feet) |
|---|---|---|---|---|---|---|---|---|
| SMWSS, CA | 99 | 2,081 | 50,124 | 43,668 | *29.1%* | 6,455 | *4.3%* | 1,700 |
| Uinta, UT | 100 | 13,800 | 21,093 | 11,922 | *7.9* | 9,171 | *6.1* | 6,000 |
| Socal, CA | 100 | 3,580 | 33,441 | 17,972 | *12.0* | 15,469 | *10.3* | 1,200 to 11,500 |
| DJ, CO/KS/NE | 47 | 67,344 | 18,620 | 10,374 | *6.9* | 8,246 | *5.5* | 2,600 |
| NMWSS, CA | 100 | 1,898 | 16,343 | 16,343 | *10.9* | - | - | 1,500 |
| Piceance, CO | 5 to 95 | 3,160 | 10,641 | 1,991 | *1.3* | 8,650 | *5.7* | 9,300 |
| Totals | | | **150,262** | **102,270** | ***68.1%*** | **47,991** | ***31.9%*** | |

Our asset base has changed considerably since early 2003. As of December 31, 2006, we had 150 MMBOE of proved reserves and have abundant drilling inventories at several of our core areas. Generally, our California assets are mature (diatomite and Poso Creek are the exception) and generate more cash flow from operations than is required to reinvest in these assets. We have high capital needs in the Piceance, Uinta and the DJ basins, where we have large undeveloped resources. We anticipate spending most of our operating cash flow over the next several years in converting the recoverable hydrocarbons to production, cash flow and earnings.

**California**

California's three asset teams are South Midway-Sunset (SMWSS), North Midway-Sunset (NMWSS) (which includes diatomite) and Southern California (Socal) (which include Poso Creek, Ethel D, Placerita and Montalvo). Approximately $91 million will be invested in California projects in 2007 with $9 million, $55 million and $27 million allocated for the SMWSS, NMWSS and Socal assets, respectively.

***SMWSS, San Joaquin Valley Basin (SJVB)*** - We own and operate working interests in 38 properties, including 23 owned in fee, in the Midway-Sunset field. Production from this field relies on thermal EOR methods, primarily cyclic steaming.

2006 - Development activities were focused on horizontal drilling.

2007 - Capital is focused on further horizontal infill well drilling, targeting steam injection wells and improved subsurface well monitoring.

Production averaged approximately 10,000 Bbl/D in 2006. This is our most mature thermally enhanced asset and we are developing and testing new concepts to place heat into the remaining oil column to maximize recovery and value. We are also improving our steam monitoring capabilities to verify efficient steam placement.

***NMWSS, SJVB*** - On November 1, 2006, we announced our plans to commence development of our Midway-Sunset diatomite oil project in California based on the performance of a two-year pilot program. We believe the project will be a significant asset for our California operations and for Berry. The project will add material production and reserves as a part of our growth strategy. Over the next four years, we intend to invest an additional $210 million in capital to drill 520 shallow development wells in the fairway of the asset and add steam generation and processing facilities. We expect this development will increase production by up to 7,000 Bbl/D by 2010 (in 2006 the project averaged 325 Bbl/D). As we develop the fairway, we will also appraise the potential of recovering additional reserves in the outer portions of our acreage in subsequent development phases. We believe that the fairway contains 55% of the oil resource and has reservoir properties similar to our initial pilot. This will enable a repeatable development like those used in our other California assets.

2006 - Completed commercial testing.

2007 - Capital is focused on drilling the diatomite first phase development wells and adding steam generation equipment and various facilities. We will also be initiating steam drive pilots in one of our largest remaining hydrocarbon resources in the Tulare sands on our Main Camp property in the Midway-Sunset field.

During 2006 we redeveloped our Pan property on the non-diatomite section of NMWSS by drilling over 40 infill locations and adding steam generation capacity and associated production facilities. Production responded by increasing from approximately 100 Bbl/D to a peak of over 800 Bbl/D. Further infill drilling locations are currently being evaluated.

***Socal, SJVB and Los Angeles Basin*** - We acquired the Poso Creek properties in early 2003 and have proceeded with a successful thermal EOR redevelopment. At acquisition the property was producing less than 50 BOE/D and we averaged 940 Bbl/D in 2006.

2006 - Activity was directed at delineating the extent of the reservoir, infill drilling and expansion of the steam drive pilot. Production from this property increased as a result of thermal redevelopment steadily throughout the year from approximately 500 Bbl/D to over 1,500 Bbl/D at December 31, 2006. Additional steam generation capacity was added during the first half of the year along with 15 infill/delineation wells and late in the fourth quarter we began drilling 20 additional infill wells.

2007 - Capital is directed at drilling 34 infill producer locations, adding additional steam generation capacity and expanding the steam drive area.

In the Placerita field in the Los Angeles basin, we own and operate working interests in 13 properties, including 9 leases and 4 fee properties. Production relies on thermal recovery methods, primarily steam flooding.

2006 - We reassessed our existing steam drive and discovered additional remaining reserves within the existing mature steam drive area. Several infill wells were drilled and confirmed our assessment. Further reservoir analysis/simulation is in progress to determine the optimum recovery method.

2007 - Capital is directed at steam flood modifications and facility improvements.

We will also be initiating steam drive pilots in the other largest remaining hydrocarbon resources in the Monarch sands at Ethel D property in the Midway-Sunset field. We are pursuing the divestment of our Montalvo properties in Ventura County, California and have no capital allocated to the asset, which produced over 700 Bbl/D in 2006.

**Rocky Mountain/Mid-Continent**

We reorganized the structure of the Rocky Mountain/Mid-Continent region into three regional asset teams in late 2006 to strengthen our technical and business focus in the region. The three asset teams are centered around the Piceance basin Mesaverde gas development, the Uinta basin Green River and Wasatch oil exploitation and the DJ basin Niobrara gas projects. Approximately $176 million will be invested in Rocky Mountain region projects in 2007 with $118 million, $37 million and $21 million earmarked for the Piceance, Uinta and DJ basins, respectively.

***Piceance Basin, Colorado*** - In February 2006, we acquired a 50% working interest in 6,300 gross acres in the Garden Gulch property in the Grand Valley natural gas field in the Piceance basin of western Colorado for approximately $159 million. Then in June 2006, we entered into an agreement with an industry partner to jointly develop (our commitment under the agreement is approximately $153 million) the North Parachute Ranch property in the Grand Valley field in the Piceance immediately east of the Garden Gulch property. In accordance with the agreement we acquired a 5% non-operating working interest on 6,300 gross acres and a net operating working interest of 95% in 4,300 gross acres. We have financial commitments under both the 5% and the 95% working interests. See Note 5 to the financial statements. This agreement for the North Parachute Ranch property expands upon our reserves and drilling opportunities with an additional 400 locations. Production from these wells is expected to be similar to Garden Gulch wells, with initial gross production rates ranging from 1.3 to 2.0 MMcf/D.

2006 - We drilled 17 gross wells, 15 on the Garden Gulch property and two on the North Parachute Ranch property. Our industry partner drilled 53 gross wells upon which we earned 5% non-operating working interest. Our net production in 2006 averaged 4,300 Mcf/D. We have contracts for four rigs as of December 31, 2006 to proceed with our development plan. We have made significant progress in gearing up for extensive development of this asset, including additional outlets for gas sales. The Garden Gulch acreage now has 13 wells producing and initial production from the North Parachute Ranch property began late in the fourth quarter.

2007 - Capital is directed at drilling 55 to 65 Mesaverde wells along with associated land, facility and water disposal projects.

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

2006 - We continued the development of the Green River formation, including testing 20-acre infill wells to assist full development, including a 20-acre spacing pilot. During the year infield gas gathering infrastructure was upgraded with additional compression and a gas processing facility to handle increasing volumes of natural gas. In the fourth quarter of 2006, an Environmental Assessment (EA) was completed in the Ashley National Forest, clearing the way for 14 drillsites and up to 29 wells. We were able to drill and complete one well before winter access restrictions went into effect. In 2006, we drilled 101 total net wells in Brundage with 100% success rate. Daily net production averaged approximately 5,800 BOE/D.

2007 - Capital is directed at the Ashley Forest, additional 20-acre infills and high-graded locations across the field. The majority of this development program is targeted for the second half of the year due to winter wildlife stipulations.

In the Lake Canyon prospect, we hold, with an industry partner, a 169,000 gross acre block which is located immediately west of our Brundage Canyon producing properties. We will drill and operate the shallow wells which target light oil and natural gas in the Green River formation and retain up to a 75% working interest. Our partner will drill and operate deep wells which target hydrocarbons in the Mesaverde and Wasatch formations. We 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 our and our partner’s participation.

2006 - In January 2006, we announced commercial success from our first two wells on this acreage, from the same Green River formation that is productive immediately east (approximately three miles) in our Brundage Canyon field. Performance from these discovery wells suggests that expected reserves per well are on par with the Brundage Canyon field (approximately 80,000 BOE gross) that is currently being developed on 40-acre spacing. Production from these two shallow Green River wells continues to be favorable. We have a 56.25% working interest in these two wells, as the Ute Tribe elected to participate. In the third quarter, with Tribal participation, we drilled four additional shallow Green River wells that are all productive.

In the second quarter of 2006, our industry partner initiated production from a deep well completed in the Wasatch formation. Due to the success of this Wasatch discovery well, our industry partner drilled two additional Wasatch wells in the fourth quarter of 2006. These wells are currently waiting on completion. We have an 18.75% working interest in these two wells, as the Ute Tribe elected to participate in one of the two wells. Our daily net production from the Lake Canyon wells averaged approximately 87 BOE/D.

2007 - We are in the permitting process for an additional 16 shallow Green River wells which are intended to continue exploratory and development drilling on the eastern portion of our Lake Canyon acreage. Our working interest in these wells will be either 75% or 56.25% depending on Tribal participation. Our industry partner is also permitting additional deep wells for their 2007 drilling program. Our 2007 capital is directed at a methodical appraisal covering a sizeable portion of this acreage block, targeting Green River and Wasatch reservoirs.

In December 2004, we entered into a development agreement with an industry partner to develop their Coyote Flats prospect. The property is located approximately 45 miles southwest of our Brundage Canyon property.

2006 - We have three successful appraisal Ferron gas wells on the east side of the Scofield reservoir which have each tested flow rates exceeding 1,000 Mcf/D. We renegotiated the farm out obligation terms with our industry partner to earn a 50% working interest in the approximate 69,250 gross (33,500 net) acres in the project without drilling the remaining Emery coalbed methane wells. Our earning obligation was satisfied by installing a gathering system, compression and 13 mile gas pipeline to connect the three previously announced Ferron gas discoveries to sales pipelines. Construction is complete and first sales were established in December 2006. Two of the three wells are currently on production with the third being temporarily shut-in pending a water disposal solution. Our daily net production is approximately 780 Mcf/D.

2007 - No capital has been directed at this project, pending results from production tests on the three discovery wells.

***DJ Basin (includes eastern Colorado producing assets)*** - In 2005, we made three acquisitions for approximately $111 million establishing a core area in the Tri-State region (Eastern Colorado, western Kansas and southwestern Nebraska ) totaling approximately 100,000 net producing acres and 315,000 net total acres. Our primary acquisition was the Niobrara gas producing assets in Yuma County in northeastern Colorado in which we have a working interest of approximately 52%. Our other two acquisitions in the region consisted of undeveloped prospective acreage where our working interests range from 40% to 50%.

2006 - We drilled 205 wells to add production from both proved undeveloped and probable reserves and five exploratory wells and our net production averaged 16,100 Mcf/D. We participated in five 3-D seismic surveys covering in excess of 130 square miles. In the third quarter, we installed additional compression, gas gathering pipelines and high pressure pipelines that expand the capacity and connections to new markets on the Cheyenne Plains Lateral system. In our Kansas Tri-State prospect, we have drilled and completed a successful exploratory well that is an extension to our Prairie Star production in Cheyenne County, Kansas and have drilled two dry holes in the year.

2007 - Capital is directed at development drilling for Yuma County reserve growth, additional 3-D seismic in Colorado and Kansas and additional exploration in Kansas.

**Obstacles and Risks to Accomplishment of Strategies and Goals.** See Item 1A Risk Factors for a detailed discussion of factors that affect our business, financial condition and results of operations.

**Results of Operations.** Approximately 88% of our revenues are generated through the sale of oil and natural gas production under either negotiated contracts or spot gas purchase contracts at market prices. The remaining 12% of our revenues are primarily derived from electricity sales from cogeneration facilities which supply approximately 40% of our steam requirement for use in our California thermal heavy oil operations. We have invested in these facilities for the purpose of lowering our steam costs which are significant in the production of heavy crude oil.

***Revenues***. Sales of oil and gas were up 23% in 2006 compared to 2005 and up 89% from 2004. This significant improvement was due to increases in both oil and gas prices and production levels. Improvements in production volume are due to acquisitions and sizable capital investments. Improvement in prices during 2006 were due to a tighter supply and demand balance and the nervousness of the market about possible supply disruptions. Oil and natural gas prices contributed roughly half of the revenue increase and the increase in production volumes contributed the other half. Approximately 77% of our oil and gas sales volumes in 2006 were crude oil, with 82% of the crude oil being heavy oil produced in California which was sold under contracts based on the higher of WTI minus a fixed differential or the average posted price plus a premium. Our oil contracts allowed us to improve our California revenues over the posted price by approximately $21 million, $41 million and $13 million in 2006, 2005 and 2004, respectively.

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

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Sales of oil | $ 360 | $ 289 | $ 210 |
| Sales of gas | 70 | 61 | 17 |
| Total sales of oil and gas | $ 430 | $ 350 | $ 227 |
| Sales of electricity | 53 | 55 | 48 |
| Interest and other income, net | 3 | 2 | - |
| Total revenues and other income | $ 486 | $ 407 | $ 275 |
| Net income | $ 108 | $ 112 | $ 69 |
| Earnings per share (diluted) | $ 2.41 | $ 2.50 | $ 1.54 |

The following companywide results are in millions (except per share data) for the three months ended:

| | December 31, 2006 | December 31, 2005 | September 30, 2006 |
|---|---|---|---|
| Sales of oil | $ 84 | $ 75 | $ 98 |
| Sales of gas | 18 | 23 | 18 |
| Total sales of oil and gas | $ 102 | $ 98 | $ 116 |
| Sales of electricity | 13 | 18 | 12 |
| Interest and other income, net | 1 | 1 | 1 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total revenues and other income | $ | 116 | $ | 117 | $ | 129 |
| Net income | $ | 19 | $ | 30 | $ | 31 |
| Net income per share (diluted) | $ | .43 | $ | .69 | $ | .70 |

***Oil Contracts.*** See Item 1 Business.

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

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

| | | 2006 | % | | 2005 | % | | 2004 | % |
|---|---|---|---|---|---|---|---|---|---|
| **Oil and Gas** | | | | | | | | | |
| Heavy Oil Production (Bbl/D) | | 15,972 | 63 | | 16,063 | 70 | | 15,901 | 77 |
| Light Oil Production (Bbl/D) | | 3,707 | 15 | | 3,336 | 14 | | 3,345 | 16 |
| Total Oil Production (Bbl/D) | | 19,679 | 78 | | 19,399 | 84 | | 19,246 | 93 |
| Natural Gas Production (Mcf/D) | | 34,317 | 22 | | 21,696 | 16 | | 7,752 | 7 |
| Total (BOE/D) | | 25,398 | 100 | | 23,015 | 100 | | 20,537 | 100 |
| Percentage increase from prior year | | 10% | | | 12% | | | 24% | |
| | | | | | | | | | |
| Per BOE: | | | | | | | | | |
| Average sales price before hedging | $ | 48.38 | | $ | 47.01 | | $ | 33.64 | |
| Average sales price after hedging | | 46.67 | | | 41.62 | | | 30.32 | |
| | | | | | | | | | |
| Oil, per Bbl: | | | | | | | | | |
| Average WTI price | $ | 66.25 | | $ | 56.70 | | $ | 39.21 | |
| Price sensitive royalties | | (5.13) | | | (4.42) | | | (2.78) | |
| Gravity differential | | (8.20) | | | (5.22) | | | (4.93) | |
| Crude oil hedges | | (2.37) | | | (6.21) | | | (2.93) | |
| Average oil sales price after hedging | $ | 50.55 | | $ | 40.85 | | $ | 28.57 | |
| | | | | | | | | | |
| Gas, per MMBtu: | | | | | | | | | |
| Average Henry Hub price | $ | 6.97 | | $ | 8.05 | | $ | 6.13 | |
| Natural gas hedges | | .10 | | | (.11) | | | (.01) | |
| Location and quality differentials | | (1.18) | | | (1.45) | | | (.63) | |
| Average gas sales price after hedging | $ | 5.89 | | $ | 6.49 | | $ | 5.49 | |

The following table is for the three months ended:

| | December 31, 2006 | % | December 31, 2005 | % | September 30, 2006 | % |
|---|---|---|---|---|---|---|
| **Oil and Gas** | | | | | | |
| Heavy Oil Production (Bbl/D) | 16,833 | 63 | 15,997 | 68 | 16,076 | 61 |
| Light Oil Production (Bbl/D) | 3,363 | 13 | 3,438 | 14 | 4,118 | 16 |
| Total Oil Production (Bbl/D) | 20,196 | 76 | 19,435 | 82 | 20,194 | 77 |
| Natural Gas Production (Mcf/D) | 40,157 | 24 | 25,428 | 18 | 37,374 | 23 |
| Total (BOE/D) | 26,889 | 100 | 23,673 | 100 | 26,423 | 100 |
| | | | | | | |
| Per BOE: | | | | | | |
| Average sales price before hedging | $ 41.53 | | $ 51.71 | | $ 50.33 | |
| Average sales price after hedging | 42.00 | | 44.90 | | 47.28 | |
| | | | | | | |
| Oil, per Bbl: | | | | | | |
| Average WTI price | $ 60.17 | | $ 60.05 | | $ 70.54 | |
| Price sensitive royalties | (4.28) | | (5.02) | | (5.21) | |
| Quality differential | (9.06) | | (5.39) | | (8.76) | |
| Crude oil hedges | (.01) | | (7.54) | | (3.99) | |
| Average oil sales price after hedging | $ 46.82 | | $ 42.10 | | $ 52.58 | |
| | | | | | | |
| Gas, per MMBtu: | | | | | | |
| Average Henry Hub price | $ 7.24 | | $ 12.48 | | $ 6.18 | |
| Natural gas hedges | .33 | | (.41) | | (.02) | |
| Location and quality differentials | (2.68) | | (3.46) | | (1.32) | |
| Average gas sales price after hedging | $ 4.89 | | $ 8.61 | | $ 4.84 | |

***Electricity.*** We consume natural gas as fuel to operate our three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the cost-effective production of heavy oil. We sell our electricity to utilities under standard offer contracts, which are based on "avoided cost" or SRAC pricing approved by the CPUC and under which our revenues are currently linked to the cost of natural gas. Natural gas index prices are the primary determinant of our electricity sales price based on the current pricing formula under these contracts. The correlation between electricity sales and natural gas prices allows us to manage our cost of producing steam more effectively. Revenue and operating costs in the year ended 2006 were down from the year ended 2005 due to 7% lower electricity prices and 18% lower natural gas prices, respectively. We purchased approximately 38 MMBtu/D as fuel for use in our cogeneration facilities in the year ended December 31, 2006. The following table is for the years ended December 31:

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| **Electricity** | | | |
| Revenues (in millions) | $ 52.9 | $ 55.2 | $ 47.6 |
| Operating costs (in millions) | $ 48.3 | $ 55.1 | $ 46.2 |
| Decrease to total oil and gas operating expenses-per barrel | $ .50 | $ .02 | $ .19 |
| Electric power produced - MWh/D | 2,074 | 2,030 | 2,121 |
| Electric power sold - MWh/D | 1,867 | 1,834 | 1,915 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Average sales price/MWh (no hedging was in place) | $ | 77.13 | $ | 82.73 | $ | 70.24 |
| Fuel gas cost/MMBtu (after hedging and excluding transportation) | $ | 5.99 | $ | 7.30 | $ | 5.46 |

The following table is for the three months ended:

| | December 31, 2006 | December 31, 2005 | September 30, 2006 |
|---|---|---|---|
| **Electricity** | | | |
| Revenues (in millions) | $ 13.5 | $ 18.3 | $ 12.6 |
| Operating costs (in millions) | $ 12.1 | $ 18.5 | $ 11.2 |
| Electric power produced - MWh/D | 2,093 | 2,082 | 2,100 |
| Electric power sold - MWh/D | 1,861 | 1,886 | 1,895 |
| Average sales price/MWh | $ 75.05 | $ 101.73 | $ 79.42 |
| Fuel gas cost/MMBtu (excluding transportation) | $ 5.63 | $ 10.07 | $ 5.69 |

***Royalties.*** A price-sensitive royalty burdens a portion of our Midway-Sunset California property which produces approximately 3,044 BOE/D. This royalty is 75% of the amount of the heavy oil posted price above a base price which was $15.48 in 2006. This base price escalates at 2% annually, thus the threshold price is $15.79 per barrel in 2007. Amounts paid were $36 million, $29 million and $19.3 million in the years ended December 31, 2006, 2005 and 2004, respectively. Accounts payable associated with this royalty at year end 2006 was $36 million. Because our interest in the revenue varies according to crude prices, the continuing development on this property will depend on its future profitability.

A second price sensitive royalty burdened approximately 500 BOE/D at our Placerita field in California. This royalty is calculated when the sales price exceeds $26 per barrel up to a maximum. The royalty was $.5 million, $2.8 million and $1.4 million in the years ended December 31, 2006, 2005 and 2004, respectively. The maximum amount of the royalty over its life is $5 million, which was accrued from 2003 through the first quarter of 2006 and is now terminated.

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

| | Amount per BOE | | | Amount (in thousands) | | |
|---|---|---|---|---|---|---|
| | 2006 | 2005 | Change | 2006 | 2005 | Change |
| Operating costs - oil and gas production | $ 12.69 | $ 11.79 | 8% | $ 117,624 | $ 99,066 | 19% |
| Production taxes | 1.58 | 1.37 | 15% | 14,674 | 11,506 | 28% |
| DD&A - oil and gas production | 7.30 | 4.54 | 61% | 67,668 | 38,150 | 77% |
| G&A | 3.98 | 2.55 | 56% | 36,841 | 21,396 | 72% |
| Interest expense | 1.05 | .72 | 46% | 10,247 | 6,048 | 69% |
| Total | $ 26.60 | $ 20.97 | 27% | $ 247,054 | $ 176,166 | 40% |

Our total operating costs, production taxes, G&A and interest expenses for 2006, stated on a unit-of-production basis, increased 27% over 2005. The changes were primarily related to the following items:

- Operating costs: Operating costs in 2006 were 8% higher than 2005 due to an increase in well servicing activities and higher cost of goods and services in general. We installed additional steam generators in California related to various thermally enhanced oil projects and as a result of the increased steam injection, our crude oil production on these properties has continued to increase. The cost of our steaming operations on our heavy oil properties in California varies depending on the cost of natural gas used as fuel and the volume of steam injected. The following table presents steam information:

| | 2006 | 2005 | Change |
|---|---|---|---|
| Average volume of steam injected (Bbl/D) | 81,246 | 70,032 | 16% |
| Fuel gas cost/MMBtu | $ 5.99 | $ 7.30 | (18%) |

As we remain in a strong commodity price environment, we anticipate that cost pressures within our industry may continue due to greater field activity and rising service costs in general. Based on current plans, we are targeting average steam injection in 2007 of approximately 90,000 to 95,000 BSPD. Natural gas prices impact our cost structure in California by approximately $1.60 per California BOE for each $1.00 change in natural gas price.

· Production taxes: Our production taxes have increased over the last year as the value of our oil and natural gas has increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the cost of the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. During 2006 our production taxes increased as a result of higher assessed values on our properties, increased production and higher investment in mineral interests. We expect production taxes to track the commodity price generally.

· Depreciation, depletion and amortization: DD&A increased per BOE in 2006 due to a large increase in capital spending over the last two years and particularly more extensive development in fields with higher drilling costs. Higher leasehold acquisition costs in 2003 through 2006 are expected to increase our DD&A expense over the life of these assets as development increases. Our capital program is experiencing cost pressures in our labor and for goods and services commensurate with other energy developers. As these costs increase, our DD&A rates per BOE will also increase.

· General and administrative: Approximately two-thirds of our G&A is compensation or compensation related costs. Our employee headcount increased 16% as we added an important new core asset into our portfolio and as we are strengthening our talent base. We also re-examined our compensation structure and made necessary changes to attract and retain the talent needed to achieve our growth goals. We are experiencing higher employee turnover rates as the demand for experienced personnel in the energy industry is very high. Other items increasing our G&A in 2006 were contributions to fund the opposition of Proposition 87 in California, increased travel and consulting costs and a generally higher level of activity.

· Interest expense: Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, was $406 million at December 31, 2006 compared to $87 million at December 31, 2005. Average borrowings in 2006 increased as a result of our Piceance basin acquisitions during 2006 and capital expenditure program. A certain portion of our interest cost related to our Piceance basin acquisition and joint venture has been capitalized into the basis of the assets, and we anticipate a portion will continue to be capitalized during 2006 and 2007 until our probable reserves have been recategorized to proved reserves. For the year ended December 31, 2006, $9.3 million has been capitalized and we expect to capitalize approximately $20 million of interest cost during the full year of 2007.

The following table presents information about our operating expenses for the three months ended:

| | Amount per BOE | | | Amount (in thousands) | | |
|---|---|---|---|---|---|---|
| | December 31, 2006 | December 31, 2005 | September 30, 2006 | December 31, 2006 | December 31, 2005 | September 30, 2006 |
| Operating costs - oil and gas production | $ 13.69 | $ 13.69 | $ 12.73 | $ 33,804 | $ 29,710 | $ 30,950 |
| Production taxes | 1.15 | 1.35 | 2.17 | 2,840 | 2,937 | 5,286 |
| DD&A - oil and gas production | 8.24 | 5.23 | 7.39 | 20,335 | 11,560 | 17,974 |
| G&A | 4.55 | 2.49 | 3.87 | 11,231 | 5,407 | 9,419 |
| Interest expense | 1.27 | .71 | 1.11 | 3,503 | 1,548 | 2,707 |
| Total | $ 28.90 | $ 23.47 | $ 27.27 | $ 71,713 | $ 51,162 | $ 66,336 |

| | December 31, 2006 | December 31, 2005 | Change | September 30, 2006 | Change |
|---|---|---|---|---|---|
| Average volume of steam injected (Bbl/D) | 85,349 | 73,312 | 16% | 86,556 | (1%) |
| Fuel gas cost/MMBtu | $ 5.63 | $ 10.07 | (44%) | $5.69 | (1%) |

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

| | Amount per BOE | | | Amount (in thousands) | | |
|---|---|---|---|---|---|---|
| | 2005 | 2004 | Change | 2005 | 2004 | Change |
| Operating costs - oil and gas production | $ 11.79 | $ 10.09 | 17% | $ 99,066 | $ 73,838 | 34% |
| Production taxes | 1.37 | .86 | 59% | 11,506 | 6,431 | 79% |
| DD&A - oil and gas production | 4.54 | 3.96 | 15% | 38,150 | 29,752 | 28% |
| G&A | 2.55 | 2.99 | (15)% | 21,396 | 22,504 | (5)% |
| Interest expense | .72 | .27 | 167% | 6,048 | 2,067 | 193% |
| Total | $ 20.97 | $ 18.17 | 15% | $ 176,166 | $ 134,592 | 31% |

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

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

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

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

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

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

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

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***Estimated 2007 Oil and Gas Operating, G&A and Interest Expenses.***

| | Amount per BOE | | |
|---|---|---|---|
| | Anticipated range in 2007 | 2006 | 2005 |
| Operating costs-oil and gas production (1) | $ 14.50 to 15.50 | $ 12.69 | $ 11.79 |
| Production taxes | 1.50 to 2.00 | 1.58 | 1.37 |
| DD&A | 7.75 to 8.75 | 7.30 | 4.54 |
| G&A | 3.50 to 4.00 | 3.98 | 2.55 |
| Interest expense | 1.00 to 2.00 | 1.05 | .72 |
| Total | $ 28.25 to 32.25 | $ 26.60 | $ 20.97 |

*(1) Assuming natural gas prices of approximately NYMEX HH $7.50 MMBtu, we plan to inject approximately 15% greater steam levels in 2007 compared to 2006 levels.*

***Dry hole, abandonment and impairment.*** Reflected on our year ended 2006 income statement under the dry hole, abandonment and impairment line, there is $8.3 million that consists primarily of two Coyote Flats, Utah wells for $5.2 million, our 25% share in an exploration well located in the Lake Canyon project area of the Uinta basin drilled for approximately $1.6 million net to our interest and four wells in Bakken and four wells in Tri-State for $1.5 million.

For the year ended 2005, costs of $5.7 million which were incurred on one exploratory well on the Coyote Flats prospect, the Midway-Sunset property, two exploratory wells at northern Brundage Canyon, and $2.5 million of impairment on the remaining carrying value of our Illinois and eastern Kansas prospective CBM acreage were charged to expense. During 2004, we recorded costs of $.7 million on exploratory wells on the Midway-Sunset property and the Coyote Flats prospect.

***Exploration costs.*** We incurred exploration costs of $3.8 million in 2006 compared to $3.6 million and zero costs in 2005 and 2004, respectively. These costs consist primarily of geological and geophysical costs. We participated in 3-D seismic surveys at Lake Canyon, Utah and in the Tri-State area. We are projecting exploration costs in 2007 of between $1 million and $2 million.

***Income Taxes.*** The Revenue Reconciliation Act of 1990 included a tax credit for certain costs associated with extracting high-cost, capital-intensive marginal oil or gas which utilizes certain methods, including cyclic steam and steam flood recovery methods for heavy oil. Historically, we have had significant investment in qualifying costs and have been able to reduce our effective tax rate considerably. However, the federal and state EOR tax credits were fully phased out in 2006 due to the 2005 average U.S. wellhead crude oil price exceeding the allowable EOR tax credit ceiling price of $44.48 per barrel. If the average U.S. wellhead price of crude oil declines below the triggering point in future years, we expect to earn and claim the EOR credit on qualifying expenditures and therefore our effective tax rate should decline. As of December 31, 2006 we have approximately $24 million of federal and $18 million of state (California) EOR tax credit carryforwards available to reduce future cash income taxes. The EOR credits will begin to expire, if unused, in 2024 and 2015 for federal and California, respectively.

We experienced an effective tax rate of 39%, 31% and 23% in 2006, 2005 and 2004, respectively. The significant increase in effective tax rate during 2006 is primarily due to the phase out of EOR tax credits in 2006. In anticipation of the continued full EOR credit phase out in 2007, we expect our effective tax rate to be between 37% to 39%, based on WTI prices averaging between $40 and $60. See Note 9 to the financial statements for further information.

***Commodity derivatives.*** In the quarter ended March 31, 2006, we took a charge for the change in fair market value of our natural gas derivatives put in place to protect our Piceance basin acquisition future cash flows. These gas derivatives did not qualify for hedge accounting under SFAS 133 because the price index in the derivative instrument did not correlate closely with the item being hedged. The pre-tax charge in the first quarter was $4.8 million which represented the change in fair market value over the life of the contract, which resulted from an increase in natural gas prices from the date of the derivative to March 31, 2006. On May 31, 2006, we entered into basis swaps with natural gas volumes to match the volumes on our NYMEX Henry Hub collars that were placed on March 1, 2006. The combination of the derivative instruments entered into on March 1, 2006 (described above) and the basis swaps were designated as cash flow hedges in accordance with SFAS 133. Thus the unrealized net gain of $5.6 million on the income statement in the second quarter of 2006 under the caption "Commodity derivatives" is primarily the change in fair value of the derivative instrument caused by changes in forward price curves prior to designating these instruments as cash flow hedges. Post May 31, 2006 changes in the marked-to-market fair values are reflected in Other Comprehensive Income.

***Asset dispositions.*** We have significantly increased and strengthened our portfolio of assets since 2002 and expect to continue to make acquisitions. We anticipate that we will dispose of certain properties or assets over time. The assets most likely for disposition will be those that do not fit or complement our strategic growth plan, that are not contributing satisfactory economic returns given the profile of the assets, or we believe the development potential will not be meaningful to our company as a whole. We have identified several assets that fit our criteria and expect to divest of these assets in 2007. Proceeds from these sales will contribute to the funding of our capital program. Net oil and gas properties and equipment classified as held for sale is $8.9 million for the year ended December 31, 2006 in accordance with SFAS No. 144. See Note 2 to the financial statements.

***Reserve Replacement Rate***. The reserve replacement rate is calculated by dividing total new proved reserves added for the year by total production for the year. Total new proved reserves include; revision of previous estimate, improved recovery, extensions and discoveries, and purchase of reserves in place. This measure is important because it is an indication of growth in proved reserves and, thus may impact our value. We believe our calculation of this measure is substantially similar to how other companies compute reserve replacement rate. See Item 8 Supplemental Information About Oil & Gas Producing Activities (unaudited).

**Financial Condition, Liquidity and Capital Resources.** Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development and exploration drilling and the acquisition of properties. Fluctuations in commodity prices have been the primary reason for short-term changes in our cash flow from operating activities. The net long-term growth in our cash flow from operating activities is the result of growth in production as affected by period to period fluctuations in commodity prices. In the second quarter of 2006, we revised our senior unsecured revolving credit facility to increase our maximum credit amount under the facility to $750 million and increased our current borrowing base to $500 million. On October 24, 2006, we completed the sale of $200 million of ten year 8.25% senior subordinated notes and paid down our borrowings under our facility by $141 million. As of December 31, 2006, we had total borrowings under the senior unsecured revolving credit facility and senior unsecured money market line of credit of $206 million and $200 million under our senior subordinated notes.

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

In 2007, we have a developmental capital program of approximately $267 million, excluding acquisitions, plus we intend to make a final payment of $54 million associated with our Piceance joint venture. We are proceeding with this program, but may revise our plans due to lower commodity price expectations, timing of crude deliveries out of the Uinta basin, equipment availability, permitting or other factors. Our 2007 expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2007, we plan to invest approximately $176 million, or 66%, in our Rocky Mountain/Mid-Continent region assets, and $91 million, or 34%, in our California assets. Approximately half of the capital budget is focused on converting probable and possible reserves into proved reserves and on our appraisal and exploratory projects, while the other half is for the development of our proved reserves and facility costs.

***Dividends.*** We paid a special dividend of $.02 per share on September 29, 2006 and increased our regular quarterly dividend by 15%, from $.065 to $.075 per share beginning with the September 2006 dividend. Our regular annual dividend is currently $.30 per share, payable quarterly in March, June, September and December.

***Working Capital and Cash Flows.*** Cash flow from operations is dependent upon the price of crude oil and natural gas and our ability to increase production and manage costs. Combined crude oil and natural gas prices increased in 2006

(see graphs on page 33) and we increased production by 10%.

Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit arrangements. We used our long-term borrowings under our senior unsecured revolving credit facility primarily to fund property acquisitions. Generally, we use excess cash to pay down borrowings under our credit arrangement. As a result, we often have a working capital deficit or a relatively small amount of positive working capital. In 2006, the working capital deficit was substantially greater than 2005. The increase in the deficit is primarily made up of the $54.4 million property acquisition payable related to the final payment of the June 2006 Piceance transaction as compared to 2005.

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

| | 2006 | 2005 | Change |
|---|---|---|---|
| Average production (BOE/D) | 25,398 | 23,015 | +10% |
| Average oil and gas sales prices, per BOE after hedging | $ 46.67 | $ 41.62 | +12% |
| Net cash provided by operating activities | $ 243 | $ 188 | +29% |
| Working capital | $ (101) | $ (55) | (84%) |
| Sales of oil and gas | $ 430 | $ 350 | +23% |
| Long-term debt | $ 390 | $ 75 | +420% |
| Capital expenditures, including acquisitions and deposits on acquisitions (1) | $ 523 | $ 231 | +126% |
| Dividends paid | $ 13.2 | $ 13.2 | -% |

*(1) Does not include our commitment to drill wells on our Lake Canyon prospect pursuant to our joint venture or the remaining payment under our Piceance basin joint venture.*

The table below compares financial condition, liquidity and capital resources changes as of and for the three months ended (in millions, except for production and average prices):

| | December 31, 2006 | December 31, 2005 | Change | September 30, 2006 | Change |
|---|---|---|---|---|---|
| Average production (BOE/D) | 26,889 | 23,539 | 14% | 26,423 | 2% |
| Average oil and gas sales prices, per BOE after hedging | $ 42.00 | $ 44.90 | (6%) | $ 47.28 | (11%) |
| Net cash provided by operating activities | $ 58 | $ 65 | (11%) | $ 101 | (43%) |
| Working capital, excluding line of credit | $ (101) | $ (55) | (84%) | $ (154) | 34% |
| Sales of oil and gas | $ 102 | $ 98 | 4% | $ 116 | (12%) |
| Long-term debt, including line of credit | $ 390 | $ 75 | 420% | $ 330 | 18% |
| Capital expenditures, including acquisitions and deposits on acquisitions | $ 127 | $ 41 | 210% | $ 148 | (14%) |
| Dividends paid | $ 3.3 | $ 2.9 | 14% | $ 4.2 | (21%) |

In June 2005, we announced that our Board of Directors authorized a share repurchase program for up to an aggregate of $50 million of our outstanding Class A Common Stock. From June 2005 through December 31, 2006, we have purchased 818,000 shares in the open market for approximately $25 million. See Note 7 to the financial statements.

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

***Credit Facility.*** See Note 6 to the financial statements for more information.

**Contractual Obligations.**

Our contractual obligations as of December 31, 2006 are as follows (in thousands):

| Contractual Obligations | Total | 2007 | 2008 | 2009 | 2010 | 2011 | Thereafter |
|---|---|---|---|---|---|---|---|
| Long-term debt and interest | $ 609,464 | $ 28,603 | $ 28,603 | $ 28,603 | $ 28,603 | $ 212,552 | $ 282,500 |
| | 26,135 | 740 | 941 | 991 | 991 | 991 | 21,481 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Abandonment obligations | | | | | | | |
| Operating lease obligations | 14,208 | 1,822 | 1,670 | 1,375 | 1,357 | 1,357 | 6,627 |
| Property acquisition payable | 54,000 | 54,000 | - | - | - | - | - |
| Drilling and rig obligations | 107,333 | 34,260 | 28,960 | 41,989 | 2,124 | - | - |
| Firm natural gas transportation contracts | 73,795 | 4,801 | 7,584 | 8,496 | 8,659 | 8,659 | 35,596 |
| Total | $ 884,935 | $ 124,226 | $ 67,758 | $ 81,454 | $ 41,734 | $ 223,559 | $ 346,204 |

Long-term debt and interest - Our credit facility borrowings and related interest of approximately 6.4% can be paid before its maturity date without significant penalty on borrowings under our credit facility. Our bond notes and related interest of 8.25% mature in November 2016, but are not redeemable until November 1, 2011 and are not redeemable without any premium until November 1, 2014.

Operating leases - We lease corporate and field offices in California, Colorado and Texas. Rent expense with respect to our lease commitments for the years ended December 31, 2006, 2005 and 2004 was $1 million, $.6 million, and $.6 million, respectively. In 2006, we purchased an airplane for business travel which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

Drilling obligation - We intend to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the four year contract, beginning in 2006. Our minimum obligation under our exploration and development agreement is $9.6 million. Also included above, under our June 2006 joint venture agreement in the Piceance basin we must have 120 wells drilled by 2010 to avoid penalties of $.2 million per well or a maximum of $24 million.

Drilling rig obligation - We are obligated in operating lease agreements for the use of multiple drilling rigs.

Firm natural gas transportation - We have one firm transportation contract which provides us additional flexibility in securing our natural gas supply for California operations. This allows us to potentially benefit from lower natural gas prices in the Rocky Mountains compared to natural gas prices in California. We also have several long-term transportation contracts which provide us with physical access to interstate pipelines to move gas from our producing areas to markets.

**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 our 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. We believe the following accounting policies are critical policies.

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

***Oil and Gas Reserves.*** Oil and gas reserves include proved reserves that represent estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our 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 our 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 our estimated reserve quantities, increases in future cost estimates or depressed crude oil or natural gas prices could cause us to reduce the carrying amounts of our properties. We perform an impairment analysis of our proved properties annually by comparing the future undiscounted net revenue per the annual reserve valuation prepared by our independent reserve engineers to the net book carrying value of the assets. An analysis of the proved properties will also be performed whenever events or changes in circumstances indicate an asset's carrying value may not be recoverable from future net revenue. Assets are grouped at the field level and if it is determined that the net book carrying value cannot be recovered by the estimated future undiscounted cash flow, they are written down to fair value. Cash flows used in the impairment analysis are determined based on our estimates of crude oil and natural gas reserves, future crude oil and natural gas prices and costs to extract these reserves. For our unproved properties, we perform an impairment analysis annually or whenever events or changes in circumstances indicate an asset's net book carrying value may not be recoverable.

***Derivatives and Hedging.*** We follow 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, we 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. Our policy is to assess hedge effectiveness at the end of each calendar quarter.

***Income Taxes.*** We compute 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 our 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, our federal and state income tax returns are generally not filed before the financial statements are prepared. Therefore we estimate the tax basis of our 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. A valuation allowance is recognized if it is determined that deferred tax assets may not be fully utilized in future periods. 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. We may generate EOR tax credits from the production of our heavy crude oil in California which results in a deferred tax asset and believe that these credits will be fully utilized in future years and consequently have 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.*** We have 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 our asset retirement obligations (ARO) was prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires us to record the fair value of liabilities for retirement obligations of long-lived assets. 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. We obtained estimates from third parties and used the present value of estimated cash flows related to our 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 our assets, the ultimate costs to retire our wells may vary significantly from previous estimates.

***Environmental Remediation Liability.*** We review, on a quarterly basis, our estimates of costs of the cleanup of various sites including sites in which governmental agencies have designated us as a potentially responsible party. 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, our experience and the experience of 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 our oil and gas operating costs and the liability, if applicable, recorded on our balance sheet.

***Accounting for Business Combinations***. We have grown substantially through acquisitions and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations using the purchase method, which is the only method permitted under SFAS 141. The accounting for business combinations is complicated and involves the use of significant judgment. Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether in the form of cash, assets, stock or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices, where available, appraisals, comparisons to transactions for similar assets and liabilities and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Each of the business combinations completed were of interests in oil and gas assets. We believe the consideration we paid to acquire these assets represents the fair value of the assets and liabilities acquired at the time of acquisition. Consequently, we have not recognized any goodwill from any of our business combinations.

***Stock-Based Compensation.*** We adopted SFAS No. 123(R) to account for our stock option plan beginning January 1, 2006. This standard requires us to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation* effective January 1, 2004. The modified prospective method was selected as described in SFAS 148, *Accounting for Stock-Based Compensation—Transition and Disclosure*. Under this method, we recognize stock option compensation expense as if we had applied the fair value method to account for unvested stock options from the original effective date. Stock option compensation expense is recognized from the date of grant to the vesting date. The fair value of each option award is estimated on the date of grant using the Black-Scholes option pricing model that uses the following assumptions. Expected volatilities are based on the historical volatility of our stock. We use historical data to estimate option exercises and employee terminations within the valuation model; separate groups of employees that have similar historical exercise behavior are considered separately for valuation purposes. The expected term of options granted is based on historical exercise behavior and represents the period of time that options granted are expected to be outstanding; the range results from certain groups of employees exhibiting different exercise behavior. The risk free rate for periods within the contractual life of the option is based on U.S. Treasury rates in effect at the time of grant.

***Electricity Cost Allocation.*** Our investment in our cogeneration facilities has been for the express purpose of lowering steam costs in our California heavy oil operations and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam and use natural gas as fuel. We allocate steam costs to our oil and gas operating costs based on the conversion efficiency (of fuel to electricity and steam) of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. Electricity used in oil and gas operations is allocated at cost. A portion of the capital costs of the cogeneration facilities is allocated to DD&A-oil and gas production.

***Capitalized Interest.*** Interest incurred on funds borrowed to finance exploration and certain acquisition and development activities is capitalized. To qualify for interest capitalization, the costs incurred must relate to the acquisition of unproved reserves, drilling of wells to prove up the reserves and the installation of the necessary pipelines and facilities to make the property ready for production. Such capitalized interest is included in oil and gas properties, buildings and equipment. Capitalized interest is amortized over the estimated life of the respective project.

**Recent Accounting Pronouncements.** In December 2004, SFAS No. 123(R), *Share-Based Payment*, was issued which establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires an issuer to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. In April 2005, the SEC issued a rule that SFAS No. 123(R) will be effective for annual reporting periods beginning on or after June 15, 2005. As a result, we adopted this statement beginning January 1, 2006. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*. Accordingly, the adoption of SFAS No. 123(R) using the modified prospective method did not have a material impact on our condensed financial statements for the year ended December 31, 2006.

In May 2005, SFAS No. 154, *Accounting Changes and Error Corrections*, a replacement of APB Opinion No. 20 and FASB Statement No. 3 was issued. SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 became effective for our fiscal year beginning January 1, 2006. The adoption of SFAS No. 154 had no effect to our financial position and result of operations.

In February 2006, SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140* was issued. This Statement resolves issues addressed in Statement 133 Implementation Issue No. D1, *Application of Statement 133 to Beneficial Interests in Securitized Financial Assets*. SFAS No. 155 will become effective for our fiscal year beginning after September 15, 2006. While there was no impact on our financial statements as of December 31, 2006, based on our existing derivatives, we may experience a financial impact depending on the nature and extent of any new derivative instruments entered into after the effective date of SFAS No. 155.

In June 2006, the FASB issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*. This interpretation requires that realization of an uncertain income tax position must be “more likely than not” (i.e. greater than 50% likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, this interpretation prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. This interpretation also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. This interpretation is effective for fiscal years beginning after December 15, 2006, and we will be required to adopt this interpretation in the first quarter of 2007. Based on our evaluation as of December 31, 2006, we do not believe that the implementation of FIN 48 will have a material impact on our financial statements.

In September 2006, SFAS No. 157, *Fair Value Measurements* was issued by the FASB. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for our fiscal year beginning January 1, 2008, and we are currently assessing the potential impact of this Statement on our financial statements.

In September 2006, Staff Accounting Bulletin (“SAB”) No. 108*, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. Registrants must quantify the impact on current period financial statements of correcting all misstatements, including both those occurring in the current period and the effect of reversing those that have accumulated from prior periods. This SAB was adopted at December 31, 2006. The adoption of SAB No. 108 had no effect on our financial position or on the results of our operations.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity’s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement is effective beginning January 1, 2008 and we are evaluating this pronouncement.

## Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 15 to the financial statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, from time to time we enter into crude oil and natural gas hedge contracts. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in any commodity price increases. In California, we benefit from lower natural gas pricing as we are a consumer of natural gas in our operations and elsewhere, we benefit from higher natural gas pricing. We have hedged, and may hedge in the future both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate in accordance with policy established by our board of directors.

Currently, our hedges are in the form of swaps and collars. However, we may use a variety of hedge instruments in the future to hedge WTI or the index gas price. We have crude oil sales contracts in place which are priced based on a correlation to WTI. Natural gas (for cogeneration and conventional steaming operations) is purchased at the SoCal border price and we sell our produced gas in Colorado and Utah at the Colorado Interstate Gas (CIG) and Questar index prices, respectively.

The following table summarizes our hedge position as of December 31, 2006:

| Term | Average Barrels Per Day | Floor/Ceiling Prices | Term | Average MMBtu Per Day | Average Price |
|---|---|---|---|---|---|
| **Crude Oil Sales (NYMEX WTI) Collars** | | | **Natural Gas Sales (NYMEX HH TO CIG) Basis Swaps** | | |
| Full year 2007 | 10,000 | $47.50 / $70 | 2007 Average | 13,500 | $1.65 |
| Full year 2008 | 10,000 | $47.50 / $70 | 2008 Average | 18,250 | $1.50 |
| Full year 2009 | 10,000 | $47.50 / $70 | | | |
| Full year 2010 | 5,000 | $56.00 / $78.95 | **Natural Gas Sales (NYMEX HH) Collars** | Average MMBtu Per Day | Floor/Ceiling Prices |
| | | | 1st Quarter 2007 | 12,000 | $8.00 / $16.70 |
| | | | 2nd Quarter 2007 | 13,000 | $8.00 / $8.82 |
| | | | 3rd Quarter 2007 | 14,000 | $8.00 / $9.10 |
| | | | 4th Quarter 2007 | 15,000 | $8.00 / $11.39 |
| | | | 1st Quarter 2008 | 16,000 | $8.00 / $15.65 |
| | | | 2nd Quarter 2008 | 17,000 | $7.50 / $8.40 |
| | | | 3rd Quarter 2008 | 19,000 | $7.50 / $8.50 |
| | | | 4th Quarter 2008 | 21,000 | $8.00 / $9.50 |

Payments to our counterparties are triggered when the monthly average prices are above the swap or ceiling price in the case of our crude oil and natural gas sales hedges and below the swap price for our natural gas sales hedge positions. Conversely, payments from our counterparties are received when the monthly average prices are below the swap or floor price for our crude oil and natural gas sales hedges and above the swap price for our natural gas sales hedge positions.

As of February 28, 2007, we have converted 2,000 Bbl/D of our 2007 oil collars beginning on March 1, 2007 to a swap with a strike price of $60 WTI. This swap is considered to be an effective cash flow hedge and the transaction cost to convert to this swap is estimated at $.6 million on an after tax basis. We intend to proceed with additional conversions of our existing collars to swaps for a portion of our remaining 2007 collars if we can attain at least a $60 WTI strike price. Additionally, we entered into oil swaps for 1,000 Bbl/D at $64.55 from March 2007 through December 2007.

The collar strike prices will allow us to protect a significant portion of our future cash flow if 1) oil prices decline below $47.50 per barrel while still participating in any oil price increase up to $78.95 per barrel on these volumes and if 2) gas prices decline below approximately $8 per MMBtu. These hedges improve our financial flexibility by locking in significant revenues and cash flow upon a substantial decline in crude oil or natural gas prices. It also allows us to develop our long-lived assets and pursue exploitation opportunities with greater confidence in the projected economic outcomes and allows us to borrow a higher amount under our senior unsecured revolving credit facility.

While we have designated our hedges as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, it is possible that a portion of the hedge related to the movement in the WTI to California heavy crude oil price differential may be determined to be ineffective. Likewise, we may have some ineffectiveness in our natural gas hedges due to the movement of HH pricing as compared to actual sales points. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income. While we believe that the differential will narrow and move closer toward its historical level over time, there are no assurances as to the movement in the differential. If the differential were to change significantly, it is possible that our hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to our net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity.

We entered into derivative contracts (natural gas swaps and collar contracts) on March 1, 2006 that did not qualify for hedge accounting under SFAS 133 because the price index for the location in the derivative instrument did not correlate closely with the item being hedged. These contracts were recorded in the first quarter of 2006 at their fair value on the balance sheet and we recognized an unrealized net loss of approximately $4.8 million on the income statement under the caption “Commodity derivatives.” We entered into natural gas basis swaps on the same volumes and maturity dates as the previous hedges in May 2006 which allowed for these derivatives to be designated as cash flow hedges going forward, causing an unrealized net gain of $5.6 million to be recognized in the second quarter of 2006. The difference of $.8 million was recorded in other comprehensive income at the date the hedges were designated.

Additionally, on June 8, 2006 and July 10, 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility. These interest rate swaps have been designated as cash flow hedges.

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities.

Irrespective of the unrealized gains reflected in Other Comprehensive Income, the ultimate impact to net income over the life of the hedges will reflect the actual settlement values. All of these hedges have historically been deemed to be cash flow hedges with the marked-to-market valuations provided by external sources, based on prices that are actually quoted.

At December 31, 2006, Accumulated Other Comprehensive Loss, net of income taxes, consisted of $20 million of unrealized losses from our crude oil and natural gas hedges. Deferred net losses recorded in Accumulated Other Comprehensive Loss at December 31, 2006 are expected to be reclassified to earnings over the life of the contracts. 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 our hedging activities, we utilize multiple counterparties on our hedges and monitor each counterparty's credit rating.

| | | 2006 | | 2005 | | 2004 |
|---|---|---|---|---|---|---|
| Net reduction of sales of oil and gas revenue due to hedging activities (in millions) | $ | 15.7 | $ | 45.3 | $ | 24.9 |
| Net reduction of cost of gas due to hedging activities (in millions) | $ | 1.6 | $ | 5.0 | $ | 1.3 |
| Net reduction in revenue per BOE due to hedging activities | $ | 1.71 | $ | 5.39 | $ | 3.32 |

Based on NYMEX futures prices as of December 31, 2006, (WTI $66.39; HH $7.51) we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

| | 12/31/06 NYMEX Futures | Impact of percent change in futures prices on earnings | | | |
|---|---|---|---|---|---|
| | | -20% | -10% | +10% | +20% |
| Average WTI Futures Price (2007 - 2010) | $ 66.39 | $ 53.11 | $ 59.75 | $ 73.02 | $ 79.66 |
| Crude Oil gain/(loss) (in millions) | - | 2.5 | .1 | (34.8) | (108.2) |
| Average HH Futures Price (2007 - 2008) | 7.51 | 6.00 | 6.76 | 8.26 | 9.01 |
| Natural Gas gain (in millions) | 10.7 | 26.0 | 17.1 | 7.8 | 3.1 |
| | | | | | |
| Net pre-tax future cash (payments) and receipts by year (in millions): | | | | | |
| 2007 (WTI $64.35; HH $6.97) | $ 4.8 | $ 11.5 | $ 8.0 | $ (3.1) | $ (26.1) |
| 2008 (WTI $67.45; HH $8.06) | 5.9 | 14.5 | 9.1 | (9.6) | (37.2) |
| 2009 (WTI $67.21) | - | - | - | (14.3) | (38.9) |

| | | | | | |
|---|---|---|---|---|---|
| 2010 (WTI $66.53) | - | 2.5 | .1 | - | (2.9) |
| Total | $ 10.7 | $ 28.5 | $17.2 | $(27.0) | $(105.1 ) |

***Interest Rates.*** Our exposure to changes in interest rates results primarily from long-term debt. On October 24, 2006, we issued $200 million of 8.25% senior subordinated notes due 2016 in a public offering. Total long-term debt outstanding at December 31, 2006 and 2005 was $390 million and $75 million, respectively. Interest on amounts borrowed under our revolving credit facility is charged at LIBOR plus 1.0% to 1.75%, with the exception of the $100 million of principal for which we have a hedge in place to fix the interest rate at approximately 5.5% plus the senior unsecured revolving credit facility's margin through June 30, 2011. Based on year-end 2006 credit facility borrowings, a 1% change in interest rates would have a $.6 million after tax impact on our financial statements.

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


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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.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

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

We have completed integrated audits of Berry Petroleum Company's financial statements and of its internal control over financial reporting as of December 31, 2006 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 financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006 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.

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, 2006 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, 2006, 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
February 28, 2007

**BERRY PETROLEUM COMPANY**
**Balance Sheets**
**December 31, 2006 and 2005**
**(In Thousands, Except Share Information)**

| ASSETS | 2006 | 2005 |
|---|---|---|
| Current assets: | | |
| Cash and cash equivalents | $ 416 | $ 1,990 |
| Short-term investments | 665 | 661 |
| Accounts receivable | 67,905 | 59,672 |
| Deferred income taxes | - | 4,547 |
| Fair value of derivatives | 7,349 | 3,618 |
| Assets held for sale | 8,870 | - |
| Prepaid expenses and other | 13,604 | 4,398 |
| Total current assets | 98,809 | 74,886 |
| Oil and gas properties (successful efforts basis), buildings and equipment, net | 1,080,631 | 552,984 |
| Fair value of derivatives | 2,356 | - |
| Long-term deferred income taxes | - | 1,600 |
| Other assets | 17,201 | 5,581 |
| | $ 1,198,997 | $ 635,051 |
| LIABILITIES AND SHAREHOLDERS' EQUITY | | |
| Current liabilities: | | |
| Accounts payable | $ 69,914 | $ 57,783 |
| Property acquisition payable | 54,400 | - |
| Revenue and royalties payable | 45,845 | 34,920 |
| Accrued liabilities | 20,415 | 8,805 |
| Line of credit | 16,000 | 11,500 |
| Income taxes payable | - | 1,237 |
| Deferred income taxes | 745 | - |
| Fair value of derivatives | 8,084 | 15,398 |
| Total current liabilities | 215,403 | 129,643 |
| Long-term liabilities: | | |
| Deferred income taxes | 103,515 | 55,804 |
| Long-term debt | 390,000 | 75,000 |
| Abandonment obligation | 26,135 | 10,675 |
| Unearned revenue | 1,437 | 866 |
| Fair value of derivatives | 34,807 | 28,853 |
| | 555,894 | 171,198 |
| Commitments and contingencies (Note 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, 100,000,000 shares authorized; 42,098,551 shares issued and outstanding (21,157,155 on a pre-split basis in 2005) | 421 | 211 |
| Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899) (898,892 on a pre-split basis in 2005) | 18 | 9 |
| Capital in excess of par value | 50,166 | 56,064 |
| Accumulated other comprehensive loss | (19,977) | (24,380) |

| | | |
|---|---|---|
| Retained earnings | 397,072 | 302,306 |
| Total shareholders' equity | 427,700 | 334,210 |
| | $ 1,198,997 | $ 635,051 |

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

**BERRY PETROLEUM COMPANY**
**Statements of Income**
**Years ended December 31, 2006, 2005 and 2004**
**(In Thousands, Except Per Share Data)**

| | 2006 | 2005 (1) | 2004 (1) |
|---|---|---|---|
| REVENUES | | | |
| Sales of oil and gas | $ 430,497 | $ 349,691 | $ 226,876 |
| Sales of electricity | 52,932 | 55,230 | 47,644 |
| Interest and other income, net | 2,909 | 1,804 | 426 |
| | 486,338 | 406,725 | 274,946 |
| EXPENSES | | | |
| Operating costs - oil and gas production | 117,624 | 99,066 | 73,838 |
| Operating costs - electricity generation | 48,281 | 55,086 | 46,191 |
| Production taxes | 14,674 | 11,506 | 6,431 |
| Depreciation, depletion & amortization - oil and gas production | 67,668 | 38,150 | 29,752 |
| Depreciation, depletion & amortization - electricity generation | 3,343 | 3,260 | 3,490 |
| General and administrative | 36,841 | 21,396 | 22,504 |
| Interest | 10,247 | 6,048 | 2,067 |
| Commodity derivatives | (736) | - | - |
| Dry hole, abandonment, impairment and exploration | 12,009 | 9,354 | 1,155 |
| | 309,951 | 243,866 | 185,428 |
| Income before income taxes | 176,387 | 162,859 | 89,518 |
| Provision for income taxes | 68,444 | 50,503 | 20,331 |
| | | | |
| Net income | $ 107,943 | $ 112, 356 | $ 69,187 |
| | | | |
| Basic net income per share | $ 2.46 | $ 2.55 | $ 1.58 |
| | | | |
| Diluted net income per share | $ 2.41 | $ 2.50 | $ 1.54 |
| | | | |
| Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share) | 43,948 | 44,082 | 43,788 |
| Effect of dilutive securities: | | | |
| Stock options | 723 | 780 | 1,046 |
| Other | 103 | 118 | 106 |
| Weighted average number of shares of capital stock used to calculate diluted net income per share | 44,774 | 44,980 | 44,940 |

**Statements of Comprehensive Income**
**Years Ended December 31, 2006, 2005 and 2004**
**(In Thousands)**

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Net income | $ 107,943 | $ 112,356 | $ 69,187 |
| | 11,471 | (25,015) | (781) |

| | | | |
|---|---|---|---|
| Unrealized gains (losses) on derivatives, net of income taxes of $7,647, ($16,677), and ($521), respectively | | | |
| Reclassification of realized gains (losses) included in net income net of income taxes of ($4,712), $1,081 and $2,284, respectively | (7,068) | 1,622 | 3,426 |
| Comprehensive income | $ 112,346 | $ 88,963 | $ 71,832 |

(1) The 2004 and 2005 per share and share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006. See Note 7 to the financial statements.

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

**BERRY PETROLEUM COMPANY**
**Statements of Shareholders' Equity**
**Years Ended December 31, 2006, 2005 and 2004**
**(In Thousands, Except Per Share Data)**

| | Class A | Class B | Capital in Excess of Par Value | Deferred Stock-Based Compensation | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Shareholders' Equity |
|---|---|---|---|---|---|---|---|
| Balances at January 1, 2004 | $209 | $ 9 | $56,475 | $ (1,108) | $ 145,385 | $ (3,632 ) | $ 197,338 |
| Adoption of SFAS 123 | - | - | (243) | 1,108 | - | - | 865 |
| Stock-based compensation (310,538 shares) | 1 | - | 3,451 | - | - | - | 3,452 |
| Deferred director fees - stock compensation | - | - | 993 | - | - | - | 993 |
| Cash dividends declared - $.26 per share | - | - | - | - | (11,394) | - | (11,394) |
| Unrealized gain on derivatives | - | - | - | - | - | 2,645 | 2,645 |
| Net income | - | - | - | - | 69,187 | - | 69,187 |
| Balances at December 31, 2004 | 210 | 9 | 60,676 | - | 203,178 | (987) | 263,086 |
| Shares repurchased and retired (217,800 shares) | (2) | - | (6,314) | - | - | - | (6,316) |
| Stock-based compensation (294,358 shares) | 3 | - | 1,360 | - | - | - | 1,363 |
| Deferred director fees - stock compensation | - | - | 342 | - | - | - | 342 |
| Cash dividends declared - $.30 per share | - | - | - | - | (13,228) | - | (13,228) |
| Unrealized loss on derivatives | - | - | - | - | - | (23,393) | (23,393) |
| Net income | - | - | - | - | 112,356 | - | 112,356 |
| Balances at December 31, 2005 | 211 | 9 | 56,064 | - | 302,306 | (24,380) | 334,210 |
| Two-for one stock split | 211 | 9 | (220) | - | - | - | - |
| Shares repurchased and retired (600,200 shares) | (6) | - | (18,713) | - | - | - | (18,719) |
| Stock-based compensation (498,939 shares) | 5 | - | 12.700 | - | - | - | 12,705 |
| Deferred director fees - stock compensation | - | - | 335 | - | - | - | 335 |
| Cash dividends declared - $.30 per share | - | - | - | - | (13,177) | - | (13,177) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Unrealized gain on derivatives | - | - | - | - | - | 4,403 | 4,403 |
| Net income | - | - | - | - | 107,943 | - | 107,943 |
| Balances at December 31, 2006 | $ 421 | $ 18 | $50,166 | $ - | $ 397,072 | $ (19,977) | $ 427,700 |

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

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**BERRY PETROLEUM COMPANY**
**Statements of Cash Flows**
**Years Ended December 31, 2006, 2005 and 2004**
**(In Thousands)**

| Cash flows from operating activities: | 2006 | 2005 | 2004 |
|---|---|---|---|
| Net income | $ 107,943 | $ 112,356 | $ 69,187 |
| Depreciation, depletion and amortization | 71,011 | 41,410 | 33,242 |
| Dry hole | 8,253 | 5,705 | 745 |
| Abandonment and impairment | 606 | (1,381) | (1,314) |
| Commodity derivatives | (109) | - | - |
| Stock-based compensation expense, net of taxes | 6,436 | 1,703 | 5,309 |
| Deferred income taxes, net | 51,666 | 20,847 | 10,815 |
| Other, net | 447 | 278 | 794 |
| Increase in current assets other than cash, cash equivalents and short-term investments | (16,338) | (26,717) | (11,310) |
| Increase in current liabilities other than line of credit | 13,314 | 33,579 | 17,145 |
| Net cash provided by operating activities | 243,229 | 187,780 | 124,613 |
| Cash flows from investing activities: | | | |
| Exploration and development of oil and gas properties | (265,110) | (118,718) | (71,556) |
| Property acquisitions | (257,840) | (112,249) | (2,845) |
| Additions to vehicles, drilling rigs and other fixed assets | (21,306) | (11,762) | (669) |
| Capitalized interest | (9,339) | - | - |
| Deposits on potential acquisitions | - | - | (10,221) |
| Proceeds from sale of assets | 4,812 | 130 | 101 |
| Other, net | - | - | 3 |
| Net cash used in investing activities | (548,783) | (242,599) | (85,187) |
| Cash flows from financing activities: | | | |
| Proceeds from issuance of line of credit | 327,250 | 18,000 | - |
| Payment of line of credit | (322,750) | (6,500) | - |
| Proceeds from issuance of long-term debt | 569,700 | 144,000 | - |
| Payment of long-term debt | (254,700) | (97,000) | (22,000) |
| Dividends paid | (13,177) | (13,228) | (11,394) |
| Book overdraft | 15,246 | 1,921 | - |
| Repurchase of shares | (18,713) | (6,315) | - |
| Proceeds from stock option exercises | 3,156 | - | - |
| Excess tax benefit | 3,444 | - | - |
| Debt issuance cost | (5,476) | (759) | - |
| Net cash provided by (used in) financing activities | 303,980 | 40,119 | (33,394) |
| Net (decrease) increase in cash and cash equivalents | (1,574) | (14,700) | 6,032 |
| Cash and cash equivalents at beginning of year | 1,990 | 16,690 | 10,658 |
| Cash and cash equivalents at end of year | $ 416 | $ 1,990 | $ 16,690 |
| Supplemental disclosures of cash flow information: | | | |
| Interest paid | $ 15,019 | $ 5,275 | $ 1,243 |
| Income taxes paid | $ 18,148 | $ 26,544 | $ 11,652 |
| Supplemental non-cash activity: | | | |
| Increase (decrease) in fair value of derivatives: | | | |
| | $ 6,282 | $ (5,446) | $ 1,804 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Current (net of income taxes of $4,188, ($3,631), and $1,202, respectively) | | | | | | |
| Non-current (net of income taxes of ($1,252), ($11,965), and $561, respectively) | | (1,879) | | (17,947) | | 841 |
| Net increase (decrease) to accumulated other comprehensive income | $ | 4,403 | $ | (23,393 ) | $ | 2,645 |
| Non-cash financing activity: Property acquired for debt | $ | 54,000 | $ | - | $ | - |

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

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

## 1. General

We are an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. We have 66% of our oil and gas reserves in California and 34% in the Rocky Mountain/Mid-Continent region. Approximately 63% of our production is in California, most of which is heavy crude oil and is sold to a Bakersfield, California refinery. We have invested in cogeneration facilities which provide steam required for the extraction of heavy oil and which generates electricity for sale. Production of light crude oil and natural gas in the Rocky Mountain/Mid-Continent region accounts for approximately 37% of our production.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

## 2. Summary of Significant Accounting Policies

<u>Cash and cash equivalents</u> - We consider all highly liquid investments purchased with a remaining maturity of three months or less to be cash equivalents. Our cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at December 31, 2006 is $17.2 million representing outstanding checks in excess of the bank balance (book overdraft).

<u>Short-term investments</u> - Short-term investments consist principally of United States treasury notes and corporate notes with remaining maturities of more than three months at date of acquisition and are carried at fair value. We utilize specific identification in computing realized gains and losses on investments sold.

<u>Accounts receivable</u> - Trade accounts receivable are recorded at the invoiced amount. We do not have any off-balance-sheet credit exposure related to our customers. We assess credit risk and allowance for doubtful accounts on a customer specific basis. As of December 31, 2006 and 2005, we do not have an allowance for doubtful accounts.

<u>Income taxes</u> - Income taxes are provided based on the liability method of accounting. The provision for income taxes is based on reported pre-tax financial statement income. Deferred tax assets and liabilities are recognized for the future expected tax consequences of temporary differences between income tax and financial reporting, and principally relate to differences in the tax bases of assets and liabilities and their reported amounts using enacted tax rates in effect for the year in which differences are expected to reverse. If it is more likely than not that some portion or all of a deferred tax asset will not be realized, a valuation allowance is recognized.

<u>Derivatives</u> - To minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, from time to time we enter into crude oil and natural gas hedge contracts. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivative contracts that do not qualify for hedge accounting under SFAS No. 133 the contracts are recorded at fair value on the balance sheet with the corresponding unrealized gain or loss on the income statement under the caption “Commodity

derivatives." For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. The hedging relationship between the hedging instruments and hedged items, such as oil and gas, must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. We measure hedge effectiveness at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, or in the case of options based on the change in intrinsic value. A regression analysis is used to determine whether the relationship is considered to be highly effective retrospectively and prospectively. Actual effectiveness of the hedge will be calculated against the underlying cumulatively using the dollar offset method at the end of each quarter. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss, such as time value for option contracts, is recognized immediately in the statements of income. Gains and losses on hedging instruments and adjustments of the carrying amounts of hedged items are included in revenues for hedges related to our crude oil and natural gas sales and in operating expenses for hedges related to our natural gas consumption. The resulting cash flows are reported as cash flows from operating

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**2. Summary of Significant Accounting Policies (Cont'd)**

activities. See Note 15 - Hedging.

Assets held for sale - We consider an asset to be held for sale when management approves and commits to a formal plan to actively market a business for sale. Upon designation as held for sale, the carrying value of the asset is recorded at the lower of the carrying value or its estimated fair value, less costs to sell. Once an asset is determined to be "held for sale", we no longer record DD&A on the property. We anticipate that we will dispose of certain properties or assets over time. The assets most likely for disposition will be those that do not fit or complement our strategic growth plan, that are not contributing satisfactory economic returns given the profile of the assets, or that we believe the development potential will not be meaningful to our company as a whole. We have identified several assets that fit our criteria and expect to divest of these assets in 2007. Proceeds from these sales will contribute to the funding of our capital program. Net oil and gas properties and equipment classified as held for sale is $8.9 million for the year ended December 31, 2006 in accordance with SFAS No. 144.

Leases receivable - We entered into two separate three year lease agreements on two company owned drilling rigs. Each agreement has a three year purchase option in favor of the lessee. The agreements were signed in the third and second quarters of 2005 and 2006, respectively. Both agreements are accounted for as direct financing leases as defined by SFAS No. 13, *Accounting for Leases,* and included in other long term assets on the balance sheet.

Oil and gas properties, buildings and equipment - We account for our 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 and the related capitalized costs are reviewed quarterly. 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 if the well found a sufficient quantity of reserves to justify its completion as a producing well and we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The costs of development wells are capitalized whether productive or nonproductive.

Depletion of oil and gas producing properties is computed using the units-of-production method. Depreciation of lease and well equipment, including cogeneration facilities and other steam generation equipment and facilities, is computed using the units-of-production method or on a straight-line basis over estimated useful lives ranging from 10 to 20 years. Buildings and equipment are recorded at cost. Depreciation is provided on a straight-line basis over estimated useful lives ranging from 5 to 30 years for buildings and improvements and 3 to 10 years for machinery and equipment. Estimated residual salvage value is considered when determining depreciation, depletion and amortization (DD&A) rates.

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we group assets at the field level and periodically review the carrying value of our property and equipment to test whether current events or circumstances indicate that such carrying value may not be recoverable. If the tests indicate that the carrying value of the asset is greater than the estimated future undiscounted cash flows to be generated by such asset, then an impairment adjustment needs to be recognized. Such adjustment consists of the amount by which the carrying value of such asset exceeds its fair value. We generally measure fair value by considering sale prices for similar assets or by discounting estimated future cash flows from such asset using an appropriate discount rate. Considerable management judgment is necessary to estimate the fair value of assets, and accordingly, actual results could vary significantly from such estimates. When assets are sold, the applicable costs and accumulated depreciation and depletion are removed from the accounts and any gain or loss is included in income. Expenditures for maintenance and repairs are expensed as incurred.

Asset retirement obligations - We have 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 our ARO is prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*. Under this standard, we record the fair value of the future abandonment as capitalized abandonment costs in Oil and Gas Properties with an offsetting abandonment liability. We obtain estimates from third parties and use the present value of estimated cash flows related to its ARO to determine the fair value. The capitalized abandonment costs are amortized with other property costs using the units-of-production method. We increase the liability monthly by recording accretion expense using our credit adjusted interest rate. Accretion expense is included in DD&A in our financial statements.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**2. Summary of Significant Accounting Policies (Cont'd)**

Revenue recognition - Revenues associated with sales of crude oil, natural gas, and electricity are recognized when title passes to the customer, net of royalties, discounts and allowances, as applicable. Electricity and natural gas produced by us and used in our operations are not included in revenues. Revenues from crude oil and natural gas production from properties in which we have an interest with other producers are recognized on the basis of our net working interest (entitlement method).

Conventional steam costs - The costs of producing conventional steam are included in “Operating costs - oil and gas production.”

Cogeneration operations - Our investment in cogeneration facilities has been for the express purpose of lowering steam costs in our heavy oil operations and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam. We allocate steam costs to our oil and gas operating costs based on the conversion efficiency of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. Electricity used in oil and gas operations is allocated at cost. Electricity consumption included in oil and gas operating costs for the years ended December 31, 2006, 2005 and 2004 was $5.3 million, $5.7 million and $5 million, respectively.

Shipping and handling costs - Shipping and handling costs, which consist primarily of natural gas transportation costs, are included in either "Operating costs - oil and gas production" or "Operating costs - electricity generation,” as applicable. Natural gas transportation costs included in these categories were $6.8 million, $5.8 million and $5.4 million, for 2006, 2005 and 2004, respectively. Additionally, the transportation costs in the Uinta basin were first incurred in 2006 and were $1.1 million.

Production taxes - Consist primarily of severance, production and ad valorem taxes.

Stock-based compensation - We adopted SFAS No. 123(R) beginning January 1, 2006. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation* effective January 1, 2004. The primary difference between the standards was the accounting for the excess tax benefit, as the difference between the stock option grant price and the exercise price. The implementation of FAS123(R) did not have a material impact on us. We voluntarily adopted the fair value method of accounting for our stock option plan as prescribed by SFAS 123. The modified prospective method was selected as described in SFAS 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. Under this method, we recognize stock option compensation expense as if it had applied the fair value method to account for unvested stock options from its original effective date. Stock option compensation expense is recognized from the date of grant to the vesting date.

From January 1, 2004 to July 29, 2004 a minor portion of our stock option compensation was calculated under variable accounting. In accordance with variable plan accounting, we recognized a corresponding liability determined by a marked-to-market valuation of our stock at each financial reporting date. On July 29, 2004, we revised certain stock option exercise provisions of the plan and therefore variable plan accounting was no longer required.

Comprehensive income (loss) - Comprehensive income (loss) includes net income (loss) as well as unrealized gains and losses on derivative instruments, recorded net of tax.

Net income per share - Basic net income per share is computed by dividing income available to shareholders (the numerator) by the weighted average number of shares of capital stock outstanding (the denominator). Our Class B Stock is included in the denominator of basic and diluted net income. The computation of diluted net income per share is similar to the computation of basic net income per share except that the denominator is increased to include the dilutive effect of the additional common shares that would have been outstanding if all convertible securities had been converted to common shares during the period.

Environmental expenditures - We review, on a quarterly basis, our estimates of costs of the cleanup of various sites, including sites in which governmental agencies have designated us as a potentially responsible party. When it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of compliance or remediation can be determined, the applicable amount is accrued. For other potential liabilities, the timing of accruals coincides with the related ongoing site assessments. Any liabilities arising hereunder are not discounted.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**2. Summary of Significant Accounting Policies (Cont'd)**

Accounting for business combinations - We have accounted for all of our business combinations using the purchase method, which is the only method permitted under SFAS 141, *Accounting for Business Combinations*. Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether in the form of cash, assets, stock or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets. We have not recognized any goodwill from any business combinations.

Capitalized interest - Interest incurred on funds borrowed to finance exploration and certain acquisition and development activities is capitalized. To qualify for interest capitalization, the costs incurred must relate to the acquisition of unproved reserves, drilling of wells to prove up the reserves and the installation of the necessary pipelines and facilities to make the property ready for production. Such capitalized interest is included in oil and gas properties, buildings and equipment. Capitalized interest is amortized over the estimated life of the respective project.

Recent accounting developments - In December 2004, SFAS No. 123(R), *Share-Based Payment*, was issued which establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires an issuer to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. In April 2005, the SEC issued a rule that SFAS No. 123(R) would be effective for annual reporting periods beginning on or after June 15, 2005. As a result, we adopted this statement beginning January 1, 2006. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*. Accordingly, the adoption of SFAS No. 123(R) using the modified prospective method did not have a material impact on our condensed financial statements for the year ended December 31, 2006.

In May 2005, SFAS No. 154, *Accounting Changes and Error Corrections*, a replacement of APB Opinion No. 20 and FASB Statement No. 3 was issued. SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impractical to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 became effective for our fiscal year beginning January 1, 2006. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date.

In February 2006, SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140* was issued. This Statement resolves issues addressed in Statement 133 Implementation Issue No. D1, *Application of Statement 133 to Beneficial Interests in Securitized Financial Assets*. SFAS No. 155 will become effective for our fiscal year beginning after September 15, 2006. While we determined there was no impact on our financial statements as of December 31, 2006, based on our existing derivatives, we may experience a financial impact depending on the nature and extent of any new derivative instruments entered into after the effective date of SFAS No. 155.

In June 2006, the FASB issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*. This interpretation requires that realization of an uncertain income tax position must be “more likely than not” (i.e. greater than 50% likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, this interpretation prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. This interpretation also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. This interpretation is effective for fiscal years beginning after December 15, 2006, and we will be required to adopt this interpretation in the first quarter of 2007. Based on our evaluation as of December 31, 2006, we do not believe that the implementation of FIN 48 will have a material impact on our financial statements.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**2. Summary of Significant Accounting Policies (Cont'd)**

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* was issued by the Financial Accounting Standards Board (FASB). This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for our fiscal year beginning January 1, 2008, and we are currently assessing the potential impact of this Statement on our financial statements.

In September 2006, Staff Accounting Bulletin ("SAB") No. 108*, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. Registrants must quantify the impact on current period financial statements of correcting all misstatements, including both those occurring in the current period and the effect of reversing those that have accumulated from prior periods. This SAB was adopted at December 31, 2006. The adoption of SAB No. 108 had no effect on our financial position or on the results of our operations.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity's election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement is effective beginning January 1, 2008 and we are evaluating this pronouncement.

**3. Fair Value of Financial Instruments**

Cash equivalents consist principally of commercial paper investments. Cash and equivalents of $.4 million and $2 million at December 31, 2006 and 2005, respectively, are stated at cost, which approximates market.

Our short-term investments available for sale at December 31, 2006 and 2005 consist of United States treasury notes that mature in less than one year and are carried at fair value. For the three years ended December 31, 2006, realized and unrealized gains and losses of our short-term investments were insignificant to the financial statements. A United States treasury note with a market value of $.7 million is pledged as collateral to the California State Lands Commission as a performance bond on our Montalvo properties. The carrying value of our long-term debt approximates its fair value.

**4. Concentration of Credit Risks**

We sell oil, gas and natural gas liquids to pipelines, refineries and oil companies and electricity to utility companies. Credit is extended based on an evaluation of the customer's financial condition and historical payment record.

Because of our ability to deliver significant volumes of crude oil over a multi-year period, we are able to secure oil sales contracts at market or better terms.

On November 21, 2005, we entered into a new crude oil sales contract for our California production (approximately 16,000 Bbl/D) for deliveries beginning February 1, 2006 with an independent refiner. Due to the substantial estimated revenue of this contract we were able to obtain financial assurance of payment through a sizable parent guarantee.

On February 27, 2007, we entered into a multi-staged crude oil sales contract with a subsidiary of Holly Corporation (Holly) for our Uinta basin crude oil. Under the agreement, Holly will begin purchasing 3,200 gross Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in mid 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation, is a fixed percentage of WTI and approximates our expected field posted price of $13 to $16 below WTI.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**4. Concentration of Credit Risks (Cont'd)**

For the three years ended December 31, 2006, we have experienced no credit losses on the sale of oil, gas or natural gas liquids. We place our temporary cash investments with high quality financial institutions and limit the amount of credit exposure to any one financial institution. For the three years ended December 31, 2006, we have not incurred losses related to these investments. With respect to our hedging activities, we utilize more than one counterparty on our hedges and monitor each counterparty's credit rating.

The following summarizes the accounts receivable balances at December 31, 2006 and 2005 and sales activity with significant customers for each of the years ended December 31, 2006, 2005 and 2004 (in thousands). We do not believe that the loss of any one customer would impact the marketability, but may impact the profitability of our California crude oil, gas, natural gas liquids or electricity sold. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the crude oil sales customer under our February 27, 2007 contract or our current contracts could impact the marketability of a portion of our Utah crude oil volumes.

| | Accounts Receivable As of December 31, | | Sales For the Year Ended December 31, | | |
|---|---|---|---|---|---|
| Customer | 2006 | 2005 | 2006 | 2005 | 2004 |
| Oil & Gas Sales: | | | | | |
| A | $ - | $ 24,389 | $ - | $ 291,093 | $ 202,966 |
| B | 2,732 | 6,929 | 75,597 | 81,342 | 58,807 |
| C | 1,136 | - | 14,391 | - | - |
| D | 28,768 | - | 305,587 | - | - |
| E | 2,246 | 1,086 | 19,462 | 11,863 | 9,138 |
| | $ 34,882 | $ 32,404 | $ 415,037 | $ 384,298 | $ 270,911 |
| Electricity Sales: | | | | | |
| F | $ 4,279 | $ 4,375 | $ 24,335 | $ 24,391 | $ 21,755 |
| G | 5,658 | 7,806 | 28,597 | 30,893 | 26,524 |
| | $ 9,937 | $ 12,181 | $ 52,932 | $ 55,284 | $ 48,279 |

Sales amounts will not agree to the Statements of Income due primarily to the effects of hedging and price sensitive royalties paid on a portion of our crude oil sales, which are netted in "Sales of oil and gas" on the Statements of Income.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

### 5. Oil and Gas Properties, Buildings and Equipment

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

| | 2006 | 2005 |
|---|---|---|
| Oil and gas: | | |
| Proved properties: | | |
| Producing properties, including intangible drilling costs | $ 649,928 | $ 437,032 |
| Lease and well equipment (1) | 358,392 | 275,346 |
| | 1,008,320 | 712,378 |
| Unproved properties | | |
| Properties, including intangible drilling costs | 309,959 | 36,440 |
| Lease and well equipment | 25 | 267 |
| | 309,984 | 36,707 |
| | 1,318,304 | 749,085 |
| Less accumulated depreciation, depletion and amortization | 258,466 | 208,597 |
| | 1,059,838 | 540,488 |
| Commercial and other: | | |
| Land | 774 | 496 |
| Drilling rigs and equipment | 10,478 | - |
| Buildings and improvements | 5,596 | 4,351 |
| Machinery and equipment | 16,025 | 17,016 |
| | 32,873 | 21,863 |
| Less accumulated depreciation | 12,080 | 9,367 |
| | 20,793 | 12,496 |
| | $ 1,080,631 | $ 552,984 |

(1) *Includes cogeneration facility costs.*

In February 2006, we closed on an agreement with a private seller to acquire a 50% working interest in natural gas assets in the Piceance basin of western Colorado for approximately $159 million. The acquisition was funded under our existing credit facility. We purchased 100% of Piceance Operating Company LLC (which owned a 50% working interest in the acquired assets). The total purchase price was allocated as follows: $30 million to proved reserves and $129 million to unproved properties. Allocation was made based on fair value. The historical operating activities of these oil and gas assets are insignificant compared to our historical operations and therefore we have not included proforma disclosures. Piceance Operating Company LLC was dissolved subsequent to the acquisition.

In June 2006, we entered into an agreement with a party to jointly develop the North Parachute Ranch property in the Grand Valley field of the Piceance basin of western Colorado. We estimate we will pay up to $153 million to fund the drilling of 90 natural gas wells on the joint venture partner's acreage. The maximum amount of cost charged to us will not exceed $1.7 million per well. If any wells are drilled for less than $1.7 million, the excess will be returned to us. In exchange for our payments of up to $153 million, we will earn a 5% working interest (4% net revenue interest) on each of the 90 wellbores and a net working interest of 95% (79% net revenue interest) in 4,300 gross acres located elsewhere on the property. The costs of drilling and development on the 4,300 gross acres will be shared by the partners in relation to the working interests. The $153 million payment was allocated to unproved properties based on the fair value of the 5% and 95% working interests.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**5. Oil and Gas Properties, Buildings and Equipment (Cont'd)**

In July 2006, we paid $51 million, which was the first installment of the total $153 million and thereby earned the assignment of the 4,300 gross acres. On November 1, 2006, we paid the second installment of approximately $50 million. We plan to pay the third installment of approximately $54 million on May 1, 2007. Prior to 2010 we are required to drill 120 wells, bearing 95% of the cost, on our 4,300 gross acres and if not met, then we are required to pay $.2 million for each well less than 120 drilled. Additionally, if we have not drilled at least one well by mid-2011 in each 160 acre tract within the 4,300 gross acres, then that specific undrilled 160 acre tract shall be reassigned to the joint venture partner. At the date of the agreement there were no operating activities from these gas assets.

In 2005, we made three acquisitions for approximately $111 million establishing a core area in the Tri-State region (Eastern Colorado, western Kansas and southwestern Nebraska) totaling approximately 100,000 net producing acres and 315,000 net total acres. Our primary acquisition was the Niobrara gas producing assets in Yuma County in northeastern Colorado in which we have a working interest of approximately 52%. Our other two acquisitions in the region consisted of undeveloped prospective acreage where our working interests range from 40% to 50%.

In 2005, we completed several transactions whereby we now have working interests in 186,000 gross acres (46,000 net) located in the Williston Basin in North Dakota. These lease acquisitions, totaling approximately $11 million, cover several contiguous blocks located primarily on the eastern flank of the Nesson Anticline.

In July 2004, we purchased approximately 169,000 gross acres with an industry partner in the Lake Canyon prospect in Utah, of which 124,500 gross (62,250 net) acres are leased from the Ute Tribe and 44,500 gross (22,250 net) acres are fee lands. Total cost to us was approximately $2 million. We will drill and operate shallow wells which target light oil in the Green River formation and retain a 75% working interest. Our partner will drill and operate deeper wells and we will retain a 25% working interest. The Ute Tribe has the option to participate in all wells and retain up to a 25% working interest. As of December 31, 2006, our minimum obligation under our agreement is $9.6 million through 2009.

On January 27, 2005, we acquired certain interests in the Niobrara field in northeastern Colorado for approximately $105 million (J-W Acquisition) to increase natural gas reserves and production. Assets purchased include $93 million of gas properties, $6 million of pipeline, and $5 million of compression equipment. Liabilities assumed included $1 million of asset retirement obligations.

The pro forma results presented below for the year ended December 31, 2005 and 2004 have been prepared to report the effect of the J-W Acquisition on our results of operations under the purchase method of accounting as if it had been consummated on January 1, 2004. The pro forma results do not purport to represent the results of operations that actually would have occurred on such date or to project our results of operations for any future date or period. The following show the results (in thousands, except per share data):

| | 2005 | 2004 |
|---|---|---|
| Proforma | $ | $ |
| Revenue | 408,088 | 295,243 |
| Proforma Income from operations | 190,970 | 121,688 |
| | 112,660 | 72,393 |

| | | |
|---|---|---|
| Proforma Net income | | |
| Proforma Basic earnings per share | 5.11 | 3.31 |
| Proforma Diluted earnings per share | 5.01 | 3.22 |

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**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**5. Oil and Gas Properties, Buildings and Equipment (Cont'd)**

***Suspended Well Costs***

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period of greater than one year since the completion of drilling (in thousands, except number of projects):

| | | 2006 | | 2005 | | 2004 |
|---|---|---|---|---|---|---|
| Capitalized exploratory well costs that have been capitalized for a period of one year or les | $ | 89 | $ | 6,037 | $ | 2,941 |
| Capitalized exploratory well costs that have been capitalized for a period greater than one year | | - | | - | | 511 |
| Balance at December 31 | $ | 89 | $ | 6,037 | $ | 3,452 |
| | | | | | | |
| Number of projects that have exploratory well costs that have been capitalized for a period of greater than one year | | - | | - | | 1 |

The following table reflects the net changes in capitalized exploratory well costs (in thousands):

| | | 2006 | | 2005 | | 2004 |
|---|---|---|---|---|---|---|
| Beginning balance at January 1 | $ | 6,037 | $ | 3,452 | $ | 511 |
| Additions to capitalized exploratory well costs pending the determination of proved reserves | | 6,682 | | 8,840 | | 3,420 |
| Reclassifications to wells, facilities and equipment based on the determination of proved reserves | | (4,377) | | (3,369) | | - |
| Capitalized exploratory well costs charged to expense | | (8,253) | | (2,886) | | (479) |
| Ending balance at December 31 | $ | 89 | $ | 6,037 | $ | 3,452 |

In 2004, included in the amount of exploratory well costs that have been capitalized for a period of greater than one year since completion of drilling are costs of $.5 million that have been capitalized since 2003. These costs are related to our diatomite project in the Midway-Sunset field and have been reclassified from exploratory well costs to productive property in 2005.

***Dry hole, abandonment and impairment***
Reflected on our year ended 2006 income statement under the dry hole, abandonment and impairment line, there is $8.3 million that consists primarily of two Coyote Flats, Utah wells for $5.2 million, our 25% share in an exploration well located in the Lake Canyon project area of the Uinta basin drilled for approximately $1.6 million net to our interest and four wells in Bakken and four wells in Tri-State for $1.5 million.

For the year ended 2005, costs of $5.7 million which were incurred on one exploratory well on the Coyote Flats prospect, the Midway-Sunset property, two exploratory wells at northern Brundage Canyon, and impairment of $2.5 million on the remaining carrying value of our Illinois and eastern Kansas prospective CBM acreage were charged to expense. During 2004, we recorded costs of $.7 million on exploratory wells on the Midway-Sunset property and the Coyote Flats prospect.

**6. Long-term and Short-term Debt Obligations**

***Long-term debt***

In October 2006, we issued in a public offering $200 million of 8.25% senior subordinated notes due 2016. The deferred costs of approximately $5 million associated with the issuance of this debt are being amortized over the ten year life of the bonds. The net proceeds from the offering were used to 1) repay approximately $145 million of borrowings under the bank credit facility, which were $170 million as of the issuance date after the application of this payment and 2) approximately $50 million was used to finance the November 1, 2006 installment under the joint venture agreement to develop properties in the Piceance basin.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**6. Long-term and Short-term Debt Obligations (Cont'd)**

In April 2006, we completed a new unsecured five-year bank credit agreement (the Agreement) with a banking syndicate and extended the term by one year to July 2011. The Agreement is a revolving credit facility for up to $750 million and replaces the previous $500 million facility. The current borrowing base was established at $500 million, as compared to the previous $350 million. This transaction was accounted for in accordance with Emerging Issues Task Force, (EITF) 98-14, *Debtor’s Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements*.

The total outstanding debt under the credit facility’s borrowing base and line of credit was $206 million at December 31, 2006, leaving $294 million in borrowing capacity available. Interest on amounts borrowed under this debt is charged at LIBOR plus a margin of 1.00% to 1.75% or the prime rate, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. We are required under the Agreement to pay a commitment fee of .25% to .375% on the unused portion of the credit facility annually.

The maximum amount available is subject to an annual redetermination of the borrowing base in accordance with the lender's customary procedures and practices. Both we and the banks have bilateral rights to one additional redetermination each year.

The Agreement contains restrictive covenants which, among other things, require us to maintain a certain debt to EBITDA ratio and a minimum current ratio, as defined. The bond indebtedness of $200 million is subordinated to our credit facility indebtedness. Our bond indebtedness covenant limits debt to the greater of $750 million or 40% of Adjusted Consolidated Net Tangible Assets (as defined). Additionally, as long as certain interest coverage ratio (as defined) is met, we may incur additional debt. We were in compliance with all such covenants as of December 31, 2006. The weighted average interest rate on total long-term outstanding borrowings at December 31, 2006 and 2005 was 6.2% and 4.9%, respectively.

***Short-term debt***
In November 2005, we completed a new unsecured uncommitted money market line of credit (Line of Credit). Borrowings under the Line of Credit may be up to $30 million for a maximum of 30 days. The Line of Credit may be terminated at any time upon written notice by either us or the lender. At December 31, 2006 the outstanding balance under this Line of Credit was $16 million. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1%. The weighted average interest rate on outstanding borrowings on the Line of Credit at December 31, 2006 and 2005 was 7.3% and 5.4%, respectively. Additionally, on June 8, 2006 and July 10, 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility for five years. These interest rate swaps have been designated as cash flow hedges.

**7. Shareholders’ Equity**

On March 1, 2006, our Board of Directors approved a two-for-one stock split to shareholders of record on May 17, 2006, subject to obtaining shareholder approval of an increase in our authorized shares. On May 17, 2006 our shareholders approved the authorized share increase and on June 2, 2006 each shareholder received one additional share for each share in the shareholder's possession on May 17, 2006. This did not change the proportionate interest a shareholder maintained in Berry Petroleum Company on May 17, 2006. All historical shares, equity awards and per share amounts have been restated for the two-for-one stock split.

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 $.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Common Stock at the option of the holder.

In June 2005, we announced that our Board of Directors authorized a share repurchase program for up to an aggregate of $50 million of our outstanding Class A Common Stock. From June 2005 through December 31, 2006, we repurchased 818,000 shares in the open market for approximately $25 million.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**7. Shareholders' Equity (Cont'd)**

In December 2005, we adopted a plan under Rule 10b5-1 of the Securities Exchange Act of 1934 to facilitate the repurchase of our shares of common stock. Rule 10b5-1 allows a company to purchase its shares at times when it would not normally be in the market due to possession of nonpublic information, such as the time immediately preceding its quarterly earnings releases. This plan expired on December 1, 2006. This 10b5-1 plan was authorized under, and administered consistent with, our $50 million share repurchase program. We may repurchase shares in the open market from time to time during our normal trading windows or under a new plan under 10b5-1. All repurchases of common stock are made in compliance with regulations set forth by the SEC and are subject to market conditions, applicable legal requirements and other factors.

This share repurchase program does not obligate us to acquire any particular amount of common stock and the plan may be suspended at any time at our discretion.

***Dividends***
We paid a special dividend of $.02 per share on September 29, 2006 and increased our regular quarterly dividend by 15%, from $.065 to $.075 per share beginning with the September 2006 dividend. Our regular annual dividend is currently $.30 per share, payable quarterly in March, June, September and December. We paid a special dividend of $.05 per share on September 29, 2005 and increased our regular quarterly dividend by 8%, from $.06 to $.065 per share beginning with the September 2005 dividend.

As of December 31, 2006, dividends declared on 7,793,080 shares of certain Common Stock are restricted, whereby 37.5% of the dividends declared on these shares are paid by us to the surviving member of a group of individuals, the B Group, as long as this remaining member shall live.

Dividend payments are limited by covenants in our 1) credit facility to the greater of $20 million or 75% of net income, and 2) bond indenture of up to $20 million annually irrespective of our coverage ratio or net income and up to $10 million in the event we are in a non-payment default.

***Shareholder Rights Plan***
In November 1999, we adopted a Shareholder Rights Agreement and declared a dividend distribution of one Right for each outstanding share of Capital Stock on December 8, 1999. Each Right, when exercisable, entitles the holder to purchase one one-hundredth of a share of a Series B Junior Participating Preferred Stock, or in certain cases other securities, for $19.00. The exercise price and number of shares issuable are subject to adjustment to prevent dilution. The Rights would become exercisable, unless earlier redeemed by us 10 days following a public announcement that a person or group has acquired, or obtained the right to acquire, 20% or more of the outstanding shares of Common Stock, or 10 business days following the commencement of a tender or exchange offer for such outstanding shares which would result in such person or group acquiring 20% or more of the outstanding shares of Common Stock, either event occurring without the prior consent of us.

The Rights will expire on December 8, 2009 or may be redeemed by us at $.005 per Right prior to that date unless they have theretofore become exercisable. The Rights do not have voting or dividend rights, and until they become exercisable, have no diluting effect on our earnings. A total of 500,000 shares of our Preferred Stock has been designated Series B Junior Participating Preferred Stock and reserved for issuance upon exercise of the Rights.

**8. Asset Retirement Obligations**

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. In 2006, we reassessed our estimate as costs have increased due to demand for these services, resulting in an increase in the ARO balance at year end.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**8. Asset Retirement Obligations (Cont'd)**

Under SFAS 143, the following table summarizes the change in abandonment obligation for the years ended December 31 (in thousands):

| | 2006 | 2005 |
|---|---|---|
| Beginning balance at January 1 | $ 10,675 | $ 8,214 |
| Liabilities incurred | 5,711 | 2,952 |
| Liabilities settled | (862) | (1,382) |
| Revisions in estimated liabilities | 9,176 | - |
| Accretion expense | 1,435 | 891 |
| Ending balance at December 31 | $ 26,135 | $ 10,675 |

**9. Income Taxes**

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

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Current: | | | |
| Federal | $ 12,231 | $ 22,666 | $ 7,073 |
| State | 4,547 | 6,990 | 2,443 |
| | 16,778 | 29,656 | 9,516 |
| Deferred: | | | |
| Federal | 44,205 | 20,640 | 11,959 |
| State | 7,461 | 207 | (1,144) |
| | 51,666 | 20,847 | 10,815 |
| Total | $ 68,444 | $ 50,503 | $ 20,331 |

The following table summarizes the components of the total deferred tax assets and liabilities before such financial statement offsets. The components of the net deferred tax liability consist of the following at December 31 (in thousands):

| | 2006 | 2005 |
|---|---|---|
| Deferred tax asset: | | |
| Federal benefit of state taxes | $ 4,248 | $ 2,712 |
| Credit carryforwards | 33,338 | 31,929 |
| Stock option costs | 3,989 | 2,352 |
| Derivatives | 13,275 | 16,253 |
| Other, net | 3,450 | 139 |
| | 58,300 | 53,385 |
| Deferred tax liability: | | |
| Depreciation and depletion | (162,560) | (102,754) |
| Other, net | - | (289) |

| | | | | |
|---|---|---|---|---|
| | | (162,560) | | (103,043) |
| Net deferred tax liability | $ | (104,260) | $ | (49,658) |

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**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**9. Income Taxes (Cont'd)**

At December 31, 2006, our net deferred tax assets and liabilities were recorded as a current liability of $.7 million and a long-term liability of $103.5 million. At December 31, 2005, our net deferred tax assets and liabilities were recorded as a current asset of $4.5 million, a long-term asset of $1.6 million and a long-term liability of $55.8 million.

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

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Tax computed at statutory federal rate | 35% | 35% | 35% |
| State income taxes, net of federal benefit | 5 | 3 | 1 |
| Tax credits | - | (7) | (9) |
| Recognition of tax basis of properties | - | - | (5) |
| Other | (1) | - | 1 |
| Effective tax rate | 39% | 31% | 23% |

We have approximately $24 million of federal and $18 million of state (California) EOR tax credit carryforwards available to reduce future income taxes. The EOR credits will begin to expire, if unused, in 2024 and 2015 for federal and California, respectively.

**10. Leases Receivable**

We entered into two separate three year lease agreements on two company owned drilling rigs. Each agreement has a three year purchase option in favor of the lessee. The agreements were signed in the third and second quarters of 2005 and 2006, respectively. The total net investment in these rigs is approximately $8.9 million at December 31, 2006. Both agreements are accounted for as direct financing leases as defined by SFAS No. 13, *Accounting for Leases*. Net investment in both leases are included in the balance sheet as other assets and as of December 31, 2006 are as follows (in thousands):

| | |
|---|---|
| Net minimum lease payments receivable | $ 11,511 |
| Unearned income | (2,657) |
| Net investment in direct financing lease | $ 8,854 |

As of December 31, 2006, estimated future minimum lease payments, including the purchase option, to be received are as follows (in thousands):

| | |
|---|---|
| 2007 | $ 1,276 |
| 2008 | 4,545 |
| 2009 | 5,752 |
| Total | |

| |
|---|
| $ 11,573 |

***Drilling Rigs***

During 2005, we purchased two drilling rigs, which are leased to a drilling company under three-year contracts (see above). During 2006, we purchased a third rig that was refurbished in preparation for leasing under a similar drilling contract to be used for our Piceance drilling program. All three rigs carry purchase options available to the drilling company.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

## 11. Commitments and Contingencies

We have accrued environmental liabilities for all sites, including sites in which governmental agencies have designated us as a potentially responsible party, where it is probable that a loss will be incurred and the minimum cost or amount of loss can be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be higher than the liability currently accrued. Amounts currently accrued are not significant to our financial position and management believes, based upon current site assessments, that the ultimate resolution of these matters will not require substantial additional accruals. We are involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of our business. In the opinion of management, the resolution of these matters will not have a material effect on our financial position, or on the results of operations or liquidity.

Our contractual obligations not included in our balance sheet as of December 31, 2006 are as follows (in thousands):

| Contractual Obligations | Total | 2007 | 2008 | 2009 | 2010 | 2011 | Thereafter |
|---|---|---|---|---|---|---|---|
| Operating lease obligations | 14,208 | 1,822 | 1,670 | 1,375 | 1,357 | 1,357 | 6,627 |
| Drilling and rig obligations | 107,333 | 34,260 | 28,960 | 41,989 | 2,124 | - | - |
| Firm natural gas transportation contracts | 73,795 | 4,801 | 7,584 | 8,496 | 8,659 | 8,659 | 35,596 |
| Total | $ 195,336 | $ 40,883 | $ 38,214 | $ 51,860 | $ 12,140 | $ 10,016 | $ 42,223 |

<u>Operating leases</u> - We lease corporate and field offices in California, Colorado and Texas. Rent expense with respect to our lease commitments for the years ended December 31, 2006, 2005 and 2004 was $1 million, $.6 million, and $.6 million, respectively. In 2006, we purchased an airplane for business travel which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

<u>Drilling obligation</u> - We intend to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the four year contract, beginning in 2006. Our minimum obligation under our exploration and development agreement is $9.6 million. Also included above, under our June 2006 joint venture agreement in the Piceance basin we must have 120 wells drilled by 2010 to avoid penalties of $.2 million per well or a maximum of $24 million.

<u>Drilling rig obligation</u> - We are obligated in operating lease agreements for the use of multiple drilling rigs.

<u>Firm natural gas transportation</u> - We have one firm transportation contract which provides us additional flexibility in securing our natural gas supply for California operations. This allows us to potentially benefit from lower natural gas prices in the Rocky Mountains compared to natural gas prices in California. We also have several long-term transportation contracts which provide us with physical access to interstate pipelines to move gas from our producing areas to markets.

## 12. Equity Compensation Plans

On December 2, 1994, our Board of Directors adopted the Berry Petroleum Company 1994 Stock Option Plan which was restated and amended in December 1997 and December 2001 (the 1994 Plan or Plan) and approved by the shareholders in May 1998 and May 2002, respectively. The 1994 Plan provided for the granting of stock options to purchase up to an aggregate of 3,000,000 shares of Common Stock. All options, with the exception of the formula grants to non-employee Directors, were granted at the discretion of the Compensation Committee and the Board of Directors. The term of each option did not exceed ten years from the date the options were granted. The 1994 Plan expired on December 2, 2004, and the shareholders approved a new equity incentive plan in May 2005.

The 2005 Equity Incentive Plan (the 2005 Plan), approved by the shareholders in May 2005, provides for granting of equity compensation up to an aggregate of 2,900,000 shares of Common Stock. All equity grants are at market value on the date of grant and at the discretion of the Compensation Committee or the Board of Directors. The term of each employee grant did not exceed ten years from the grant date and vesting has generally been at 25% per year for 4 years or 100% after 3 years. The 2005 Plan also allows for grants to non-employee Directors. During 2006, each of the non-employee Directors received 10,000 options at the market value on the date of grant. The options granted to the non-employee Directors vest immediately. We generally use a broker for issuing new shares upon option exercise.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**12. Equity Compensation Plans (Cont'd)**

We adopted SFAS No. 123(R) to account for our stock option plan beginning January 1, 2006. This standard requires us to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation* effective January 1, 2004. The modified prospective method was selected as described in SFAS No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. Under this method, we recognized stock option compensation expense as if it had applied the fair value method to account for unvested stock options from its original effective date. Total compensation cost recognized into income was $6.1 million, $2.9 million and $4.2 million in 2006, 2005 and 2004, respectively.

***Stock Options***

The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model that uses the assumptions noted in the following table. Expected volatilities are based on the historical volatility of our stock. We use historical data to estimate option exercises and employee terminations within the valuation model; separate groups of employees that have similar historical exercise behavior are considered separately for valuation purposes. The expected term of options granted is based on historical exercise behavior and represents the period of time that options granted are expected to be outstanding; the range given below results from certain groups of employees exhibiting different exercise behavior. The risk free rate for periods within the contractual life of the option is based on U.S. Treasury rates in effect at the time of grant.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Expected volatility | 32% - 33% | 28% - 32% | 25% |
| Weighted-average volatility | 32% | 32% | 25% |
| Expected dividends | .8% - 1.0% | .92% - 1.3% | 1.27% - 2.45% |
| Expected term (in years) | 5.3 - 5.5 | 4 - 5 | 4 - 7 |
| Risk-free rate | 4.5% - 4.8% | 3.8% - 4.4% | 3.4% - 4.4% |

The following table summarizes information related to stock options outstanding and exercisable as of December 31, 2006:

| Range of Exercise Prices | Options Outstanding | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life | Options Exercisable | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life |
|---|---|---|---|---|---|---|
| $6.25 - $14.00 | 872,610 | $ 8.75 | 5.7 | 771,860 | $ 8.61 | 6.3 |
| $14.01 - $22.00 | 925,550 | 20.03 | 7.8 | 445,300 | 19.99 | 7.8 |
| $22.01 - $30.00 | 25,000 | 29.36 | 9.1 | 3,750 | 29.25 | 8.6 |
| $30.01 - $38.00 | 1,036,676 | 31.90 | 9.5 | 272,157 | 31.56 | 9.3 |
| Total | 2,859,836 | $ 20.97 | 7.8 | 1,493,067 | $ 16.24 | 6.9 |

Weighted average option exercise price information for the years ended December 31 is as follows:

| | 2006 | 2005 (1) | 2004 (1) |
|---|---|---|---|
| Outstanding at January 1 | $ 16.76 | $ 12.70 | $ 8.25 |
| Granted during the year | 32.82 | 29.56 | 20.30 |
| Exercised during the year | 10.83 | 8.40 | 7.87 |
| Cancelled/expired during the year | 19.11 | 18.68 | 9.01 |
| Outstanding at December 31 | 20.97 | 16.76 | 12.70 |
| Exercisable at December 31 | 16.24 | 12.31 | 8.80 |

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**12. Equity Compensation Plans (Cont'd)**

The following is a summary of stock option activity for the years ended December 31 is as follows:

| | 2006 | 2005 (1) | 2004 (1) |
|---|---|---|---|
| Balance outstanding, January 1 | 3,110,826 | 3,131,250 | 3,403,850 |
| Granted | 604,050 | 598,926 | 1,135,500 |
| Exercised | (526,990) | (605,200) | (1,163,100) |
| Canceled/expired | (328,050) | (14,150) | (245,000) |
| Balance outstanding, December 31 | 2,859,836 | 3,110,826 | 3,131,250 |
| Balance exercisable at December 31 | 1,493,067 | 1,423,076 | 1,376,550 |
| Available for future grant | 1,252,344 | 2,159,174 | - |
| Weighted average remaining contractual life (years) | 8 | 8 | 8 |
| Weighted average fair value per option granted during the year based on the Black-Scholes pricing model | $ 11.27 | $ 9.58 | $ 5.05 |

*(1) The 2004 and 2005 per share and share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.*

As of December 31, 2006, there was $10.5 million of total unrecognized compensation cost related to stock options granted under the Plan. This cost is expected to be recognized over a weighted-average period over 1.6 years. The tax benefit realized from stock options exercised during the year ended December 31, 2006 is $4.3 million.

| | Stock Options Year ended | | |
|---|---|---|---|
| | December 31, 2006 | December 31, 2005 (1) | December 31, 2004 (1) |
| Weighted-average grant date fair value of options issued | $ 11.27 | $ 9.58 | $ 5.05 |
| Total intrinsic value of options exercised (in millions) | 11.8 | 12.6 | 7.2 |
| Total intrinsic value of options outstanding (in millions) | 29.8 | 36.8 | 34.9 |
| Total intrinsic value of options exercisable (in millions) | 22.3 | 26.2 | 20.7 |

*(1) The 2004 and 2005 share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.*

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**12. Equity Compensation Plans (Cont'd)**

***Restricted Stock Units***
Under the 2005 Equity Plan, we began a long-term incentive program whereby restricted stock units (RSUs) are available for grant to certain employees. Granted RSUs generally vest at either 25% per year over 4 years or 100% after 3 years. Unearned compensation under the restricted stock award plan is amortized over the vesting period. We pay cash compensation on the RSUs in an equivalent amount of actual dividends paid on a per share basis of our outstanding common stock.

The following is a summary of RSU activity for the year ended December 31, 2006 as follows:

| | RSUs | Weighted Average Intrinsic Value at Grant Date | Weighted Average Contractual Life Remaining |
|---|---|---|---|
| Balance outstanding, January 1 | 141,900 | $ 30.65 | 3.0 years |
| Granted | 372,480 | 31.86 | |
| Converted | (29,825) | 30.65 | |
| Canceled/expired | (25,400) | 31.32 | |
| Balance outstanding, December 31 | 459,155 | $ 31.59 | 3.3 years |

| | RSUs Year ended December 31, 2006 | December 31, 2005 (1) | December 31, 2004 |
|---|---|---|---|
| Weighted-average grant date fair value of RSUs issued | $ 31.86 | $ 30.65 | $ - |
| Total intrinsic value of RSUs vested (in millions) | 1.0 | - | - |
| Total intrinsic value of RSUs outstanding (in millions) | 14.2 | 4.1 | - |

*(1) The 2005 share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.*

The total compensation cost related to nonvested awards not yet recognized on December 31, 2006 is $13 million and the weighted average period over which this cost is expected to be recognized is 1.8 years.

**13. 401(k) Plan**

We sponsor a defined contribution thrift plan under section 401(k) of the Internal Revenue Code to assist all employees in providing for retirement or other future financial needs. In December 2005, the 401(k) Plan was amended whereby effective January 1, 2006, our matching contribution is $1.00 for each $1.00 contributed by the employee up to 8% of an employee's eligible compensation. Prior to January 1, 2006, the employer match ranged from $1.00 to $1.50 for each $1.00 contributed by the employee up to 6% of an employee's eligible compensation. The employer match amount was based on the achievement of certain monthly profit levels. Our contributions to the

401(k) Plan were $1.2 million, $1.1 million and $.8 million for 2006, 2005 and 2004, respectively. Employees are eligible to participate in the 401(k) Plan on their date of hire and approximately 92% of our employees participated in the 401(k) Plan in 2006.

**14. Director Deferred Compensation Plan**

We established a non-employee director deferred stock and compensation plan to permit eligible directors, in recognition of their contributions to us, to receive fees as compensation and to defer recognition of their compensation in whole or in part to a Stock Unit Account or an Interest Account. When the eligible director ceases to be a director, the distribution from the Stock Unit Account shall be made in shares using an established market value date. The distribution from the Interest Account shall be made in cash. The aggregate number of shares which may be issued to eligible directors under the plan shall not exceed 500,000, subject to adjustment for corporate transactions that change the amount of outstanding stock. The plan may be amended at any time, but not more than once every six months, by the Compensation Committee or the Board of Directors and shall terminate, unless extended, on May 31, 2008.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

### 14. Director Deferred Compensation Plan (Cont'd)

Amounts allocated to the Stock Unit Account have the right to receive an amount equal to the dividends per share we declare as applicable. The dividend payment date and this "dividend equivalent" shall be treated as reinvested in an additional number of units and credited to their account using an established market value date. Amounts allocated to the Interest Account are credited with interest at an established interest rate.

Shares earned and deferred in accordance with the plan as of December 31, 2006, 2005 and 2004 were 13,387, 13,770 and 14,962, respectively.

### 15. Hedging

From time to time we enter 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 our future financial commitments. This hedging program is designed to moderate the effects of a severe crude oil price downturn and protect certain operating margins in our California operations. Currently, the hedges are in the form of swaps and collars, however we may use a variety of hedge instruments in the future. Management regularly monitors the crude oil and natural gas markets and our 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 marked-to-market valuations provided by external sources, based on prices that are actually quoted.

In June 2005, we entered into derivative instruments (zero-cost collars) for approximately 10,000 Bbl/D for the period January 1, 2006 through December 31, 2009. Based on WTI pricing, the floor is $47.50 and the ceiling is $70 per barrel. 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 our hedging activities, we utilize multiple counterparties on our hedges and monitor each counterparty's credit rating. After the June hedge transaction, a significant credit risk concentration existed in one broker. In July 2005, we reduced the concentration as the hedges were transferred to multiple counterparties. We are not required to issue collateral on these hedging transactions.

We entered into derivative contracts (natural gas swaps and collar contracts) on March 1, 2006 that did not qualify for hedge accounting under SFAS 133 because the price index for the location in the derivative instrument did not correlate closely with the item being hedged. These contracts were recorded in the first quarter of 2006 at their fair value on the balance sheet and we recognized an unrealized net loss of approximately $4.8 million on the income statement under the caption "Commodity derivatives." We entered into natural gas basis swaps on the same volumes and maturity dates as the previous hedges in May 2006 which allowed for these derivatives to be designated as cash flow hedges going forward. We recognized an unrealized net gain of $5.6 million in the second quarter of 2006. The net gain of $.8 million was recorded in other accumulated comprehensive income at the date the hedges were designated and will be amortized to revenue as the related sales occur.

Additionally, on June 8, 2006 and July 10, 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility for five years. These interest rate swaps have been designated as cash flow hedges.

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities. At December 31, 2006, our net fair value of derivatives liability was $33.2 million as compared to $40.6 million at

December 31, 2005. Based on NYMEX strip pricing as of December 31, 2006, we expect to make hedge payments under the existing derivatives of $4.8 million during the next twelve months. At December 31, 2006 and 2005, Accumulated Other Comprehensive Loss consisted of $20 million and $ 24.4 million, respectively, net of tax, of unrealized losses from our crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at December 31, 2006. Deferred net losses recorded in Accumulated Other Comprehensive Loss at December 31, 2006 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts.

**BERRY PETROLEUM COMPANY**
**Notes to the Financial Statements**

**16. Quarterly Financial Data (unaudited)**

The following is a tabulation of unaudited quarterly operating results for 2006 and 2005 (in thousands, except per share data).

| 2006 | Operating Revenues | Income Before Taxes | Net Income | Basic Net Income Per Share (1) | Diluted Net Income Per Share (1) |
|---|---|---|---|---|---|
| First Quarter | $ 117,101 | $ 38,084 | $ 23,251 | $ .53 | $ .52 |
| Second Quarter | 122,356 | 57,197 | 34,203 | .78 | .76 |
| Third Quarter | 128,760 | 50,477 | 31,374 | .71 | .70 |
| Fourth Quarter | 115,212 | 30,629 | 19,115 | .44 | .43 |
| | $ 483,429 | $ 176,387 | $ 107,943 | $ 2.46 | $ 2.41 |
| | | | | | |
| 2005 | | | | | |
| First Quarter | $ 87,847 | $ 33,367 | $ 22,505 | $ .51 | $ .50 |
| Second Quarter | 92,339 | 37,322 | 25,260 | .57 | .56 |
| Third Quarter | 109,372 | 48,765 | 34,219 | .78 | .76 |
| Fourth Quarter | 115,363 | 43,405 | 30,372 | .69 | .68 |
| | $ 404,921 | $ 162,859 | $ 112,356 | $ 2.55 | $ 2.50 |

*(1) The 2005 per share and share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006. See Note 7.*

**BERRY PETROLEUM COMPANY**

**Supplemental Information About Oil & Gas Producing Activities (Unaudited)**

The following sets forth costs incurred for oil and gas property acquisition, development and exploration activities, whether capitalized or expensed (in thousands):

| Property acquisitions (1) | 2006 | 2005 | 2004 |
|---|---|---|---|
| Proved properties | $ 33,390 | $ 97,348 | $ 440 |
| Unproved properties | 224,450 | 24,566 | 2,405 |
| Development (2) | 277,613 | 112,255 | 66,664 |
| Exploration (3) | 22,435 | 11,310 | 5,506 |
| | $ 557,888 | $ 245,479 | $ 75,015 |

*(1) Costs incurred for proved and unproved property acquisitions in 2005 include the reclassification of 2004 deposits of $5,505 and $4,716, respectively.*
(2) *Development costs include $.5 million, $.6 million and $.7 million that were charged to expense during 2006, 2005 and 2004, respectively.*
(3) *Exploration costs include $3.8 million and $3.6 million that were charged to expense during 2006 and 2005, respectively. Exploration costs include $9.3 million of capitalized interest.*

The following sets forth results of operations from oil and gas producing and exploration activities (in thousands):

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Sales to unaffiliated parties | $ 430,497 | $ 349,691 | $ 226,876 |
| Production costs | (132,298) | (110,572) | (80,269) |
| Depreciation, depletion and amortization | (67,668) | (38,150) | (29,752) |
| Dry hole, abandonment, impairment and exploration | (12,009) | (9,354) | (745) |
| | 218,522 | 191,615 | 116,110 |
| Income tax expenses | (85,970) | (57,872) | (33,840) |
| Results of operations from producing and exploration activities | $ 132,552 | $ 133,743 | $ 82,270 |

The following estimates of proved oil and gas reserves, both developed and undeveloped, represent our owned interests located solely within the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

Disclosures of oil and gas reserves which follow are based on estimates prepared by independent engineering consultants as of December 31, 2006, 2005 and 2004. Such estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. These estimates do not include probable or possible reserves. The information provided does not represent management's estimate of our expected future cash flows or value of proved oil and gas reserves.

**BERRY PETROLEUM COMPANY**

**Supplemental Information About Oil & Gas Producing Activities (Unaudited) (Cont'd)**

***Changes in estimated reserve quantities***

The net interest in estimated quantities of proved developed and undeveloped reserves of crude oil and natural gas at December 31, 2006, 2005 and 2004, and changes in such quantities during each of the years then ended were as follows (in thousands):

| | 2006 | | | 2005 | | | 2004 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil Mbbls | Gas Mmcf | BOE | Oil Mbbls | Gas Mmcf | BOE | Oil Mbbls | Gas Mmcf | BOE |
| Proved developed and Undeveloped reserves: | | | | | | | | | |
| Beginning of year | 103,733 | 135,311 | 126,285 | 105,549 | 25,724 | 109,836 | 106,640 | 19,680 | 109,920 |
| Revision of previous estimates | (512) | (222) | (553) | (681) | 4,084 | - | 2,975 | 8,246 | 4,349 |
| Improved recovery | 11,900 | - | 11,900 | 753 | - | 753 | 2,021 | - | 2,021 |
| Extensions and discoveries | 4,100 | 78,000 | 17,100 | 6,228 | 24,605 | 10,329 | 2,736 | 714 | 2,855 |
| Property sales | - | - | - | (1,035) | - | (1,035) | (127) | (77) | (140) |
| Production | (7,183) | (12,526) | (9,270) | (7,081) | (7,919) | (8,401) | (7,044) | (2,839) | (7,517) |
| Purchase of reserves in place (1) | 500 | 25,800 | 4,800 | - | 88,817 | 14,803 | 132 | - | 132 |
| Royalties converted to working interest | - | - | - | - | - | - | (1,784) | - | (1,784) |
| End of year | 112,538 | 226,363 | 150,262 | 103,733 | 135,311 | 126,285 | 105,549 | 25,724 | 109,836 |
| | | | | | | | | | |
| Proved developed reserves: | | | | | | | | | |
| Beginning of year | 78,308 | 70,519 | 90,061 | 78,207 | 20,048 | 81,549 | 78,145 | 12,207 | 80,180 |
| End of year | 84,782 | 104,934 | 102,270 | 78,308 | 70,519 | 90,061 | 78,207 | 20,048 | 81,549 |

*(1) See above and Note 5 to the financial statements.*

The standardized measure has been prepared assuming year end sales prices adjusted for fixed and determinable contractual price changes, current costs and statutory tax rates (adjusted for tax credits and other items), and a ten percent annual discount rate. No deduction has been made for depletion, depreciation or any indirect costs such as general corporate overhead or interest expense. Cash outflows for future production and development costs include cash flows associated with the ultimate settlement of the asset retirement obligation.

***Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves (in thousands):***

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Future cash inflows | $ 6,195,547 | $ 6,088,170 | $ 3,281,155 |

| | | | |
|---|---|---|---|
| Future production costs | (2,497,785) | (2,297,638) | (1,405,432) |
| Future development costs | (511,886) | (333,722) | (216,859) |
| Future income tax expenses | (892,669) | (1,115,516) | (355,764) |
| Future net cash flows | 2,293,207 | 2,341,294 | 1,303,100 |
| 10% annual discount for estimated timing of cash flows | (1,110,939) | (1,089,914) | (616,352) |
| Standardized measure of discounted future net cash flows | $ 1,182,268 | $ 1,251,380 | $ 686,748 |
| Average sales prices at December 31: | | | |
| Oil ($/Bbl) | $ 46.15 | $ 48.38 | $ 29.49 |
| Gas ($/Mcf) | $ 4.45 | $ 7.91 | $ 6.61 |
| BOE Price | $ 41.23 | $ 48.21 | $ 29.87 |

**BERRY PETROLEUM COMPANY**

**Supplemental Information About Oil & Gas Producing Activities (Unaudited) (Cont'd)**

***Changes in standardized measure of discounted future net cash flows from proved oil and gas reserves (in thousands):***

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Standardized measure - beginning of year | $ 1,251,380 | $ 686,748 | $ 528,220 |
| Sales of oil and gas produced, net of production costs | (300,619) | (240,039) | |