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

FORM 10-K/A

x Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2007**
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, or a smaller reporting company. See definition of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filerx Accelerated filero 0; Non-accelerated filero Smaller reporting companyo
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO x
As of June 29, 2007, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $1,376,613,441. As of February 1, 2008, the registrant had 42,585,553 shares of Class A Common Stock outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on February 1, 2008 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.

Explanatory Note

We are filing this Form 10-K/A to correct the labels on the bar chart on page 29 and to correct a typographical error in exhibit 23.1 All other information remains unchanged.

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Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Form 10-K that are not historical facts are forward-looking statements that involve risks and uncertainties. Words or forms of words such as "will," "might," "intend," "continue," "target," "expect," "achieve," "strategy," "future," "may," "could," "goal,", "forecast," "anticipate," or other comparable words or phrases, or the negative of those words, and other words of similar meaning, indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length on page 14 in Part I, Item 1A in this Form 10-K filed with the Securities and Exchange Commission, under the heading "Risk Factors."

PART I

Item 1. Business

General. We are an independent energy company engaged in the production, development, acquisition, exploitation of and exploration for, crude oil and natural gas. While we were incorporated in Delaware in 1985 and have been a publicly traded company since 1987, we can trace our roots in California oil production back to 1909. In 2003, we purchased and began operating properties in the Rocky Mountains. 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, 2007 unless noted otherwise.

Our website, located at http://www.bry.com, can be used to access recent news releases and Securities and Exchange Commission (SEC) filings, crude oil price postings, our Annual Report, Proxy Statement, Board committee charters, Corporate Governance Guidelines, code of business conduct and ethics, the code of ethics for senior financial officers, and other items of interest. 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, as applicable. We have large crude oil resources in place in the San Joaquin Valley basin, California, with diatomite being our largest, and a resource play in the Uinta basin, Utah (Lake Canyon). In 2006, we invested in a large undeveloped probable natural gas reserve position in the Piceance basin in Colorado, and are planning to continue significant drilling there over the next several years. We have a proven track record of developing reserves on a competitive basis and have increased annual production for over six years.
- ***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. In the last three years we have completed over $400 million of gas-oriented acquisitions in Colorado, establishing two core areas (the DJ and Piceance basins) of growth for us. We will continue to review asset acquisitions that meet our economic criteria with a primary focus on large repeatable development potential in the United States and concentrating on opportunities where we have strong technical expertise. Additionally, we seek to increase our net revenue interest in assets that we already operate.
- ***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 may 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 are interested in adding acreage positions near our existing producing operations to leverage our operating and technical expertise within the area and to build on established core operations. We believe this strategy can add value by utilizing our operational knowledge in a given area and by expanding our operations efficiently.
- ***Investing our capital in a disciplined manner and maintaining a strong financial position.*** The oil and gas business is capital intensive. Therefore we focus on utilizing our available capital on projects where we are likely to have success in increasing production and/or reserves at attractive returns. We believe that maintaining a strong financial position allows us to capitalize on investment opportunities and to 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.

- ***High quality asset portfolio with a long reserve life.*** Over the last several years we have diversified our asset base through acquisitions and now have approximately 40% of our production and proved reserves in the Rocky Mountain region with the balance in California. Our proved reserves consist of 69% crude oil and 31% natural gas. Our 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, 2007 our implied reserve life was 16.5 years and our implied proved developed reserve life was 10.1 years.
- ***Track record of efficient proved reserve and production growth.*** For the three years ended December 31, 2007, our average annual reserve replacement rate was 316% at an average cost of $12.23 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 15% and 9%, respectively. We were able to deliver that growth predominantly through low-risk drilling. In 2007, we achieved an average gross 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 operate our assets through six integrated teams organized around our six core areas of operations. These teams have clear objectives in production, reserves, finding and development costs, operating costs and are charged with value enhancement. In the last several years we have 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 98% 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 $550 million.
- ***Established risk management policies.*** We actively manage our exposure to commodity price fluctuations by hedging a portion of our forecasted production. We use hedges to assist us in mitigating 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 assist us in mitigating price differential volatility and in assuring product delivery to markets. Currently, the operation of our cogeneration facilities in California provides a partial hedge against increases in natural gas prices (which translates into higher steam costs) because of the high correlation between electricity and natural gas prices under our existing electricity sales contracts.

Proved Reserves and Revenues. As of December 31, 2007, our estimated proved reserves were 169 million BOE, of which 60% are heavy crude oil, 9% light crude oil and 31% natural gas. We have a geographically diverse asset base with 60% of our reserves located in California, and 40% in the Rocky Mountains. Of our proved reserves 61% were proved developed, while proved undeveloped reserves make up 39% of our proved total. The projected future capital to develop these proved undeveloped reserves is $677 million at an estimated cost of approximately $10.21 per BOE. Approximately 62% of the capital to develop these reserves is expected to be expended in the next five years. Production in 2007 was 9.8 million BOE, up 6% from production of 9.3 million BOE in 2006.

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, 2007) of approximately 16.5 years as compared to 15.3 years at year end 2006.

We have organized our operations into six asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including diatomite (N. Midway), Southern California including Poso Creek and Placerita (S. Cal), Piceance, Uinta and DJ. The following table sets forth the estimated quantities of proved reserves and production attributable to our asset teams as of December 31, 2007. We operate 98% of these assets:

State	Name	Type	Average Daily Production (BOE/D)	% of Daily Production	Proved Reserves (BOE) in millions	% of Proved Reserves	Oil & Gas Revenues before hedging (in millions)	% of Oil & Gas Revenues before hedging
CA	S. Midway	Heavy oil	9,616	36%	52.4	31%	$ 189.0	39%
UT	Uinta	Light oil/Natural gas	5,743	21	23.4	14	91.6	19
CA	S. Cal	Heavy oil	4,265	16	26.3	16	101.8	21
CO	DJ	Natural gas	3,123	12	21.1	12	34.2	7
CA	N. Midway	Heavy oil	2,068	8	22.8	13	50.4	10
CO	Piceance	Natural gas	1,715	6	23.1	14	16.4	3
	Other (1)	Heavy oil/Natural gas	372	1	.1	-	5.8	1
Totals			26,902	*100%*	169.2	*100%*	$ 489.2	*100%*

(1) Primarily relates to properties sold during 2007.

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, 2007. 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, 2007. 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 S. Midway, N. Midway and S. Cal assets contain predominantly heavy crude oil which requires heat, supplied in the form of steam, which is injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. We utilize cyclic steam and/or steam flood recovery methods on all assets. Field operations related to oil production include the initial recovery of the crude oil and its transport through treating facilities into storage tanks. After the treating process is completed, which includes removal of water and solids by mechanical, thermal and chemical processes, the crude oil is metered through automatic custody transfer units or gauged before sale and subsequently transferred into crude oil pipelines owned by other companies or transported via truck.

In the Rocky Mountains, crude oil produced from the Uinta properties is transported by truck. Natural gas produced from the Uinta, DJ and Piceance basin properties is transported to one of several main pipelines. We have seven firm transportation contracts on four different pipelines to provide transport for our Rocky Mountain natural gas production. See table on page 7.

<u>Crude Oil and Natural Gas Marketing.</u>

Economy. Global and California crude oil demand continues to remain strong although pricing is volatile. Product prices continued to exhibit an overall-strengthening trend through December 2007. Oil is a globally priced commodity and is priced according to the supply and demand of crude oil and its products. The weakness of the U.S. dollar in 2007 has contributed to a rise in the price of crude oil denominated in U.S. dollars. This price action is a contributor to the volatility of the commodity. Other dominant factors in the pricing of our crude oil include the condition of the global economy and political tension in or near oil producing regions. The range of West Texas Intermediate (WTI) crude prices for 2007, based upon NYMEX settlements, was a low of $50.48 and a high of $98.18. We expect that crude prices will continue to be volatile in 2008.

	2007	2006	2005
Average NYMEX settlement price for WTI	$ 72.41	$ 66.25	$ 56.70
Average posted price for Berry's:			
Utah 40 degree black wax (light) crude oil	59.28	56.34	53.03
California 13 degree API heavy crude oil	61.64	54.38	44.36
Average crude price differential between WTI and Berry's:			
Utah light 40 degree black wax (light) crude oil	13.13	9.91	3.67
California 13 degree API heavy crude oil	10.77	11.87	12.34

The above posting prices and differentials are not necessarily amounts paid or received by us due to the contracts discussed below. The crude oil price differential between WTI and California's heavy crude has remained relatively stable in 2007 and 2006. On December 31, 2007 the differential was $12.44 and ranged from a low of $9.11 to a high of $12.47 per barrel during the year. Crude oil price differentials between WTI and Utah's 40 degree black wax (light) crude oil were fairly consistent during 2007. On December 31, 2007 the differential was $14.50 and ranged from a low of $12.41 to a high of $14.50 per barrel during the year.

Oil Contracts. We market our crude oil production to competing buyers which may be an independent or a major oil refining company.

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 with an independent refiner for substantially all of our California production for deliveries beginning February 1, 2006 and ending January 31, 2010. After the initial term of the contract, we have a one-year renewal at our option. 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 $8.10, or 2) heavy oil field postings plus a premium of approximately $1.35. The agreement effectively eliminates our exposure to the risk of a widening WTI to California heavy crude price differential over the four year contract term and allows us to effectively hedge our production based on WTI pricing. This contract allowed us to improve our California revenues by $15 million and $21 million over the posted price in 2007 and 2006, respectively.

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.

Utah - During 2007, our Utah light crude oil was sold under multiple contracts with different purchasers for varying pricing terms, and in some cases our realized price was 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. We experienced increasing difficulty in locating additional buyers of our crude oil production from this region in the latter part of 2006. Our Utah crude oil is a paraffinic 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, put 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 refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D on July 1, 2007. Upon completion of its refinery expansion in Salt Lake City, which is expected in the first half of 2008, the refiner will increase its total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI, which was near the posted price at the contract's starting date. As global and regional prices of crude oil have risen in 2007, we are receiving crude oil prices below the posted price, although this posted price is thinly traded and does not necessarily indicate the actual price at which a seller can market their crude oil. While our price differentials have widened as the crude oil price increased, we are able to sell 100% of our crude oil to a refiner and avoid any field shut down due to the inability of placing the crude. The margins on our Uinta crude allow us to reinvest in drilling the field and to retain and increase the overall value of the field. As of January 1, 2008 this contract is our only sales contract for our Uinta oil.

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.

Natural Gas Marketing. We market our produced natural gas from Colorado and Utah. 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. Approximately two-thirds of the pricing of our natural gas is tied to the Panhandle Eastern Pipeline (PEPL) index and the remaining volume to the Colorado Interstate Gas (CIG) Index; both indices are lower than NYMEX Henry Hub prices.

	2007	2006	2005
Annual average closing price per MMBtu for:			
NYMEX Henry Hub (HH) prompt month natural gas contract last day	$ 6.86	$ 7.23	$ 8.62
Rocky Mountain Questar first-of-month indices (Uinta sales)	3.69	5.36	6.73
Rocky Mountain CIG first-of-month indices (DJ and Piceance sales)	3.97	5.63	6.95
Mid-Continent PEPL first-of-month indices (CO, KS, UT & WY sales)	5.99	6.02	7.29
Average natural gas price per MMBtu differential between NYMEX HH and:			
Questar	3.17	1.87	1.89
CIG	2.89	1.60	1.67
PEPL	.87	1.21	1.33

Gas Basis Differential. Natural gas prices in the Rockies continue to be volatile due to various factors, including takeaway pipeline capacity, supply volumes, and regional demand issues. The basis differential between HH and CIG has narrowed, as anticipated, upon the startup of the Rockies Express pipeline in early 2008. We have contracted a total of 35,000 MMBtu/D on this pipeline under two separate transactions to provide firm transport for our Piceance basin gas production. The CIG basis differential per MMBtu, based upon first-of-month values, averaged $2.89 below HH and ranged from $.51 to $5.31 below HH in 2007. Although related to CIG, the actual basin price varies. Gas from the Piceance basin traded slightly below the CIG price while Uinta basin gas sold for approximately $.40 below CIG pricing. DJ Basin gas is priced using one of two indices. Approximately two-thirds of our volumes from our DJ natural gas properties is tied to the PEPL index for pricing and the remaining volumes to CIG pricing. For that portion of the production with firm transportation on either the Cheyenne Plains Pipeline or the KMIGT pipeline, pricing is based upon the PEPL index which averaged approximately $.87 below the HH index before the cost of transportation is considered. The remainder of the DJ Basin gas is sold slightly above the CIG index price.

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

Firm Transportation Summary.

Name	From	To	Quantity (Avg. MMBtu/D)	Term	December 31, 2007 base cost per MMBtu	Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$ 0.643	$ 15,012
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 2/2018	1.098(1)	101,941
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	1/2008 to 1/2018	1.064(1)	39,205
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,500	9/2003 to 4/2012	0.174	687
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,859	9/2003 to 4/2012	0.174	787
Questar Pipeline	Brundage Canyon, UT	Goshen, UT	5,000	9/2003 to 4/2012	0.257	2,033
KMIGT	Yuma County, CO	Grant, KS	2,500	1/2005 to 10/2013	0.227	1,209
Cheyenne Plains Gas Pipeline	Yuma County, CO	Kiowa County, KS	11,000(2)	1/2007 to 12/2016	0.342	12,369
Total			70,859			$ 173,243

(1) Base cost per MMBtu is a weighted average cost.
(2) Quantity varies by year, but averages 11,000 per day over the ten year term.

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, 2007, approximately 60% of our proved reserves, or 101.6 million barrels, consisted of heavy crude oil produced from depths of less than 2,000 feet. In pursuing our goal of being a cost-efficient heavy oil producer in California, we have consistently focused on minimizing our steam cost. We believe one of the main methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on our properties. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility, are located in S. Midway. We also own a 42 MW cogeneration facility which is located in the Placerita field. Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine that would otherwise be wasted, to produce steam. This increases the efficiency of the combined process and consumes less fuel than would be required to produce the steam and electricity separately. The reduction in fuel use also results in a corresponding reduction of greenhouse gas (GHG) emissions.

Conventional Steam Generation. In addition to these cogeneration plants, we own 23 fully permitted conventional boilers. The quantity of boilers operated at any point in time is dependent on 1) the steam volume required for us to achieve our targeted production and 2) the price of natural gas compared to the realized price of crude oil sold.

Total barrels of steam per day (BSPD) capacity as of December 31, 2007 is as follows:

Steam generation capacity of conventional boilers	67,700
Steam generation capacity of cogeneration plants	38,000
Additional steam purchased under contract with a third party	2,000
Total steam capacity	107,700

The average volume of steam injected for the years ended December 31, 2007 and 2006 was 87,990 and 81,246 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 oil recovery.

In 2007, we have added additional steam capacity for our development projects at N. Midway, primarily diatomite, and Poso Creek to achieve maximum production from these properties. In 2008, we plan to add one additional 5,000 BSPD generator at Poso Creek and three additional 5,000 BSPD generators on our diatomite producing properties.

We operated most of our conventional steam generators in 2007 to achieve our goal of increasing heavy oil production. Approximately 62% 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 12% of supply volume is purchased based upon the PG&E Citygate index and used in our Poso Creek steaming operations.

	2007	2006	2005
Average SoCal Border Monthly Index Price per MMBtu	$ 6.38	$ 6.29	$ 7.37
Average Rocky Mountain NWPL Monthly Index Price per MMBtu	3.95	5.66	6.96
Average PG&E Citygate Monthly Index Price per MMBtu	6.86	6.70	7.72

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 (DJ) gas acquisition. Subsequent to 2005, we have been a net seller of gas and will benefit operationally when gas prices are higher. We are a net seller of gas with a balance between natural gas consumed and produced. The following table shows our average 2007 and estimated average 2008 amount of production in excess of consumption and hedged volumes (in average MMBtu/D):

	2007	Estimated 2008
Natural gas produced:		
DJ	18,500	18,500
Uinta (associated gas)	15,000	15,000
Piceance and other	11,000	21,000
Total natural gas volumes produced in operations	44,500	54,500
Natural gas consumed:		
Cogeneration operations	27,000	27,000
Conventional boilers (1)	18,000	24,000
Total natural gas volumes consumed in operations	45,000	51,000
Less: Our estimate of approximate natural gas volumes consumed to produce electricity (2)	(24,000)	(21,000)
Total approximate natural gas volumes consumed to produce steam	21,000	30,000
Natural gas volumes hedged	15,000	18,000
Amount of natural gas volumes produced in excess of volumes consumed to produce steam and volumes hedged	8,500	6,500

(1) In 2008, we will have additional conventional capacity at Poso Creek and diatomite to increase our production from these fields.
(2) We estimate this volume based on electricity revenues divided by the gas 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 MW, of which we consume approximately 9 MW for use in our operations. Each facility is centrally located on certain of our oil producing properties. Thus the steam generated by the facility is capable of being delivered to numerous wells that require steam for the EOR process. Our investment in our cogeneration facilities has been for the express purpose of lowering the steam costs in our heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam boilers. Cogeneration costs are allocated between electricity generation and oil and gas operations based on the conversion efficiency (of fuel to electricity and steam) of each cogeneration facility and certain direct costs to produce steam. Cogeneration costs allocated to electricity will vary based on, among other factors, the thermal efficiency of our cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of our power contracts. Although we account for cogeneration costs as described above, economically we view any profit or loss from the generation of electricity as a decrease or increase, respectively, to our total cost of producing heavy oil in California. 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) of energy plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. During most periods natural gas is the marginal fuel for California utilities, so this formula provides a hedge against our cost of gas to produce electricity and steam in our cogeneration facilities. On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes prospectively the way SRAC energy prices will be determined for existing and new SO contracts and revises the capacity prices paid under current SO1 contracts. The decision also requires California utilities to offer new contracts for energy and as-available capacity (similar to an SO1) and new contracts for energy and firm capacity (similar to an SO2) for a term of up to ten years. The new pricing methodology provides for a gradual transition of SRAC energy prices to market prices for electricity. Based on our preliminary analysis, we do not believe that the proposed pricing changes will materially affect us in 2008.

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 are currently analyzing whether to exercise our right under the SRAC Decision to replace each of these three SO1 contracts prior to its scheduled termination with one of the new SO contracts ordered by the SRAC Decision.

Based on the current pricing mechanism for our electricity under the contracts, we expect that our electricity revenues will be in the $50 million to $60 million range for 2008.

During the California energy crisis in 2000 and 2001, we had two Power Purchase Agreements with Edison and two with PG&E. Under these contracts, we were paid under an SRAC formula which included pricing gas off of the Southern California Border Spot Average. In various CPUC and court documents, this price point is often referred to as Topock. The Topock compressor site is located just inside the California border at Needles, California. On March 27, 2001, the CPUC issued a decision making certain changes in the then SRAC formula, the most significant of which was changing the pricing point from the Southern California Border to Malin (in northern California), which resulted in a significant reduction in the price we were to be paid by Edison and PG&E. The extreme disruption that this caused in the cogeneration industry caused Edison to enter into settlement agreements with us and other similarly situated gas fired QFs by which Edison nevertheless agreed to pay using the Southern California Border pricing point from March 27th forward. The CPUC approved the settlements. In various ongoing proceedings, the utilities argued the revised SRAC formula should be retroactively applied to the period from December 2000 to March 27, 2001. The CPUC has indicated in the past it did not believe retroactive adjustment should be made. On February 7, 2008, the CPUC Administrative Law Judge (ALJ) issued an order indicating that the ALJ intended to deal with a pending remand on this issue and ordered the utilities to report the number and identity of QF's still subject to this unresolved issue. We expect we may be one of those QF's. The ALJ also invited interested parties to propose solutions to the pending remand dispute. We intend to vigorously oppose any retroactive application of the March 27, 2001 decision and believe that any resolution of such dispute should be immaterial to us.

Facility and Contract Summary.

Location and Facility	Type of Contract	Purchaser	Contract Expiration	Approximate Megawatts Available for Sale	Approximate Megawatts Consumed in Operations	Approximate Barrels of Steam Per Day
Placerita						
Placerita Unit 1	SO2	Edison	Mar-09	20	-	6,500
Placerita Unit 2	SO1	Edison	Dec-09	16	4	6,500
S. Midway						
Cogen 18	SO1	PG&E	Dec-09	12	4	6,700
Cogen 38	SO1	PG&E	Dec-09	37	-	18,000

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).

Employees. On December 31, 2007, we had 263 full-time employees, up from 243 full-time employees on December 31, 2006.

Capital Expenditures Summary (Excluding Acquisitions).

The following is a summary of the developmental capital expenditures incurred during 2007 and 2006 and budgeted capital expenditures for 2008 (in thousands):

	2008 (Budgeted) (1)	2007	2006	
S. Midway Asset Team				
New wells and workovers	$ 27,948	$ 13,174	$ 15,904	
Facilities - oil & gas	2,872	7,576	7,572	
Facilities - cogeneration	-	-	415	
General	-	150	411	
	30,820	20,900	24,302	
N. Midway Asset Team				
New wells and workovers	43,143	12,949	28,707	
Facilities - oil & gas	23,530	17,125	12,884	
General	200	634	67	
	66,873	30,708	41,658	
S. Cal Asset Team				
New wells and workovers	9,615	16,627	9,493	
Facilities - oil & gas	7,328	17,549	6,234	
Facilities - cogeneration	2,850	604	177	
General	850	483	-	
	20,643	35,263	15,904	
Uinta Asset Team				
New wells and workovers	48,060	52,700	104,397	
Facilities	1,326	3,151	5,966	
General	1,450	602	1,072	
	50,836	56,453	111,434	
Piceance Asset Team				
New wells and workovers	93,900	103,921	36,654	
Facilities	16,776	15,298	3,486	
General	-	164	75	
	110,676	119,383	40,215	
DJ Asset Team				
New wells and workovers	7,826	14,017	20,979	
Facilities	3,497	2,736	7,883	
General	1,691	1,519	427	
	13,014	18,272	29,289	
Other Fixed Assets	1,750	4,288	23,614	(2)
TOTAL	$ 294,612	$ 285,267	$ 286,416	

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

(2) Other Fixed Assets in 2006 were primarily made up of two drilling rig purchases.

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

	2007	2006	2005
Net annual production: (1)			
Oil (Mbbl)	7,210	7,182	7,081
Gas (MMcf)	15,657	12,526	7,919
Total equivalent barrels (MBOE) (2)	9,819	9,270	8,401
Average sales price:			
Oil (per Bbl) before hedging	$ 57.85	$ 52.92	$ 47.04
Oil (per Bbl) after hedging	53.24	50.55	40.83
Gas (per Mcf) before hedging	4.53	5.48	7.88
Gas (per Mcf) after hedging	5.27	5.57	7.73
Per BOE before hedging	49.72	48.38	47.01
Per BOE after hedging	47.50	46.67	41.62
Average operating cost - oil and gas production (per BOE)	14.38	12.69	11.79

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

Acreage and Wells. As of December 31, 2007, our properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	5,512	5,512	521	521	6,033	6,033
Colorado	89,383	70,610	157,099	75,384	246,482	145,994
Illinois	-	-	746	63	746	63
Kansas	-	-	138,632	104,190	138,632	104,190
Utah (1) (2)	39,280	36,635	183,176	77,780	222,456	114,415
Wyoming	3,520	539	1,746	276	5,266	815
Other	80	19	-	-	80	19
	137,775	113,315	481,920	258,214	619,695	371,529

(1) Includes 1,600 gross developed and 42,983 gross undeveloped acres at Lake Canyon. We have an interest in 75% of the shallow rights and 25% of the deep rights, which is reduced when the Tribe participates.
(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 over a four year contract period beginning in 2006.

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, 2007, we have 3,872 gross productive wells (3,183 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.

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

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled (1):						
Productive	5	3	7	3	13	6
Dry (2)	-	-	5	1	1	1
Development wells drilled:						
Productive	411	314	532	356	213	176
Dry (2)	7	5	7	5	7	5
Total wells drilled:						
Productive	416	317	539	359	226	182
Dry (2)	7	5	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.

	2007	
	Gross	Net
Total productive wells drilled:		
Oil	230	227
Gas	186	90

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, all of which are operational. Owning these rigs has allowed us to successfully meet a portion of our drilling needs in the Uinta and Piceance basins. As the rig market and our rig requirements change, we evaluate the necessity to continue to own these rigs and may dispose of one or all of such rigs over time. See Note 10 to the financial statements.

Other. At year end, we had two subsidiaries accounted for under the equity method (see Note 1 to the financial statements). We had no special purpose entities and no off-balance sheet debt. See discussion of our related party transaction at Note 17 to the financial statements.

<u>Environmental and Other Regulations.</u> 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 costs. There can be no assurances, however, that changes in, or additions to, laws and regulations regarding the protection of the environment will not have an impact in the future. We maintain insurance coverage that 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 posting of drilling bonds and the reports concerning operations. Regulations may also govern the location of wells, the method of drilling and casing wells, the rates of production or "allowables," the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the notifying of surface owners and other third parties. Certain laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. We are also subject to various laws and regulations pertaining to Native American tribal surface ownership, to Native American oil and gas leases and other exploration agreements, fees, taxes, or other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations.

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

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

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. The oil and natural gas markets fluctuate widely, and we cannot predict future oil and natural gas prices. Oil prices have recently been at historically high levels and natural gas prices have been at high levels over the past several years when compared to prior periods. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- regional, domestic and foreign supply and perceptions of supply of and demand for oil and natural gas;
- level of consumer demand;
- weather conditions;
- overall domestic and global political and economic conditions, including those in the Middle East and South America;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;
- the impact of increasing liquefied natural gas, or LNG, deliveries to the United States;

- technological advances affecting energy consumption and supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the capacity, cost and availability of oil and natural gas pipelines and other transportation facilities, and the proximity of these facilities to our wells; and
- the price and availability of alternative fuels.

Our revenue, profitability and cash flow depend upon the prices and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

- reduce the amount of cash flow available to make capital expenditures or make acquisitions;
- reduce the number of our drilling locations;
- negatively impact the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically; and
- limit our ability to borrow money or raise additional capital.

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

Our heavy crude in California may be less economic than lighter crude oil and natural gas. As of December 31, 2007, approximately 60% of our proved reserves, or 101.6 million barrels, consisted of heavy oil. Light crude oil represented 9% and natural gas represented 31% 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 $8.10 below WTI, the U.S. benchmark crude oil pricing. Regional pricing can influence commodity prices. 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.

A widening of commodity differentials may adversely impact our revenues and our economics. Our crude oil and natural gas are priced in the local markets where the production occurs based on local or regional supply and demand factors. The prices that we receive for our crude oil and natural gas production are generally lower than the relevant benchmark prices, such as NYMEX, that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict natural gas and crude oil differentials.

Price differentials may widen in the future. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be adversely impacted by a widening differential on the products we sell. Our oil and natural gas hedges are based on WTI or natural gas index prices, so we may be subject to basis risk if the differential on the products we sell widens from those benchmarks and we do not have a contract tied to those benchmarks. Additionally, insufficient pipeline capacity or trucking capability and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and natural gas producing areas. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could adversely affect our financial condition.

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

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

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

Utah - During 2007, our Utah light crude oil was sold under multiple contracts with different purchasers for varying pricing terms, and in some cases our realized price was 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. We experienced increasing difficulty in locating additional buyers of our crude oil production from this region in the latter part of 2006. Our Utah crude oil is a paraffinic 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, put 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 refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D on July 1, 2007. Upon completion of its refinery expansion in Salt Lake City, which is expected in the first half of 2008, the refiner will increase its total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI, which was near the posted price at the contract’s starting date. As global and regional prices of crude oil have risen in 2007, we are receiving crude oil prices below the posted price, although this posted price is thinly traded and does not necessarily indicate the actual price at which a seller can market their crude oil. While our price differentials have widened as the crude oil price increased, we are able to sell 100% of our crude oil to a refiner and avoid any field shut down due to the inability of placing the crude. The margins on our Uinta crude allow us to reinvest in drilling the field and to retain and increase the overall value of the field. As of January 1, 2008 this contract is our only sales contract for our Uinta oil.

We may not be able to deliver minimum crude oil volumes required by our sales contract. Production volumes from our Uinta properties over the next six years are uncertain and there is no assurance that we will be able to consistently meet the minimum contractual requirement. Upon completion of the refiner’s refinery expansion in Salt Lake City, which is expected in the first half of 2008, the refiner will increase its total purchased volumes to 5,000 Bbl/D through June 30, 2013. During the term of the contract, the minimum number of delivered barrels (“base daily volume”) is 3,200 Bbl/D increasing to 5,000 Bbl/D upon the certified completion of the refinery upgrade. In the event that we cannot produce the necessary volume, we may need to purchase crude to meet our contract requirements.

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 35% of our steam capacity. These facilities are dependent on reasonable power contracts for the sale of electricity. If, for any reason, including if utilities that purchase electricity from us are no longer required by regulation to enter into power contracts with us, we were unable to enter into new or replacement contracts or were to lose any existing contract, we may not be able to supply 100% of the steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements and availability of equipment. The financial cost and timing of such new investment may adversely affect our production, capital outlays and cash provided by operating activities. We have power contracts which expire in 2009 covering our electricity generation.

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 as a result 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-quarter of our current requirement.

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

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

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates. It is not possible to measure underground accumulations of oil or natural gas in an exact way. Estimating accumulations of oil and gas is a complex process that relies on subjective 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.

Future commodity price declines and/or increased capital costs may result in a write-down of our asset carrying values which could adversely affect our results of operations and limit our ability to borrow funds. Declines in oil and natural gas prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments.

We capitalize costs to acquire, find and develop our oil and gas properties under the successful efforts accounting method. If net capitalized costs of our oil and gas properties exceed fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties annually and at any time when events or circumstances indicate a review is necessary, based on estimated prices as of the end of the reporting period. The carrying value of oil and gas properties is computed on a field-by-field basis. Once incurred, a writedown of oil and gas properties is not reversible at a later date even if oil or gas prices increase. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our credit facility.

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

Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and gas industry. These larger companies may have a greater ability to continue drilling activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

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

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

The oil and gas business involves many operating risks that can cause substantial losses; insurance will 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 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 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 federal and state restrictions on greenhouse gas emissions that may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas we produce. On September 27, 2006, California’s governor signed into law the “California Global Warming Solutions Act of 2006” Assembly Bill (AB) 32, which establishes a statewide cap on GHG that will reduce the state’s GHG emissions to 1990 levels by 2020. The California Air Resources Board (“ARB”) has been designated as the lead agency to establish and adopt regulations to implement AB 32 by January 1, 2012. Other state agencies are involved in this effort. ARB is working on mandatory reporting regulations and early action measures to reduce GHG emissions prior to the 2012 date. A number of our personnel are involved in monitoring the establishment of these regulations through industry trade groups and other organizations in which we are a member. Similar laws and regulations may be adopted by other states in which we operate or by the federal government. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, such as carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. It is not possible, at this time, to estimate accurately how regulations to be adopted by ARB or that may be adopted by others to address GHG emissions would impact our business.

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. 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. Any contracts in effect at the time of such determination would not be affected. Such a determination has not been made for our service areas in California; however, one of the California utilities has indicated that an application for relief will be filed upon the implementation of certain changes to the California electricity markets. Those market changes are not expected to occur until late in 2008. While the granting of an application for relief by FERC would not affect any of our current SO contracts, it could limit the availability of future contracts pursuant to PURPA. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates different than the utilities' avoided costs.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase. Our natural gas gathering operations are generally exempt from FERC regulation under the Natural Gas Act of 1938, or NGA, but FERC regulation still affects our gathering operations. FERC has recently proposed to require major non-interstate pipelines, including natural gas gathering pipelines (to comply with certain Internet posting requirements) with the goal of promoting transparency in the interstate natural gas market. The proposed rule would exclude from the posting requirement non-interstate pipelines flowing annually ten million MMBtus or less of gas, lying entirely upstream of a processing plant or delivering more than 95% of their gas directly to end users. FERC has not yet issued a final rule on that proposed rulemaking. We may experience an increase in costs if the rule is adopted as proposed.

Other FERC regulations may indirectly impact our gathering and natural gas production and sales operations. FERC's policies and practices across the range of its natural gas regulatory activities (including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion) may affect access to natural gas transportation. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to transportation capacity.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress. Accordingly the classification and regulation of some of our natural gas gathering facilities may be subject to change based on future determinations by FERC, the courts, or Congress.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, or EP Act 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

State regulation of natural gas gathering facilities and intrastate transportation pipelines generally includes various safety, environmental and, in some circumstances, nondiscriminatory take and common purchaser requirements, and complaint-based rate regulation. Natural gas gathering may receive greater regulatory scrutiny at the state level because in recent years FERC has permitted interstate pipeline transmission companies to transfer their gathering facilities to unregulated affiliates. Our gathering operations could be adversely affected in the future should they become subject to the application of state or federal regulation of rates and services. These operations may also be, or become subject to, safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of such facilities. Other state regulations may not directly apply to our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from natural gas wells. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect our business.

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 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. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, the future prices of oil and natural gas, revenues and costs, including synergies;
- an inability to integrate successfully the properties and businesses we acquire;
- a decrease in our liquidity to the extent we use a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

Our decision to acquire a property or business will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential problems. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

If third-party pipelines interconnected to our natural gas wells and gathering facilities become partially or fully unavailable to transport our natural gas, our results of operations and financial condition could be adversely affected.We depend upon third party pipelines that provide delivery options from our wells and gathering facilities. Since we do not own or operate these pipelines, their continuing operation in their current manner is not within our control. If any of these third-party pipelines become partially or fully unavailable to transport our natural gas, or if the gas quality specifications for their pipelines change so as to restrict our ability to deliver natural gas to those pipelines, our revenues and cash available for distribution could be adversely affected.

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

We 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, rig availability and access to our drilling locations utilizing available roads. As of December 31, 2007, we own three drilling rigs, two of which are drilling on our properties, and have additional 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, 2007) 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, 54, has been President and Chief Executive Officer since June 2004. Mr. Heinemann was Chairman of the Board and interim President and Chief Executive Officer from April 2004 to June 2004. From December 2003 to March 2004, Mr. Heinemann acted as the director designated to serve as the presiding director at executive sessions of the Board in the absences of the Chairman and as liaison between the independent directors and the CEO. Mr. Heinemann joined the Board in March of 2003. From 2000 until 2002, Mr. Heinemann served as the Senior Vice President and Chief Technology Officer of Halliburton Company and as the Chairman of the Halliburton Technology Advisory Committee. He was previously with Mobil Oil Corporation (Mobil) where he served in a variety of positions for Mobil and its various affiliate companies in the energy and technical fields from 1981 to 1999, with his last responsibilities as Vice President of Mobil Technology Company and General Manager of the Mobil Exploration and Producing Technical Center.

RALPH J. GOEHRING, 51, has been Executive Vice President and Chief Financial Officer since June 2004. Mr. Goehring served as Senior Vice President from April 1997 to June 2004, has been Chief Financial Officer since March 1992, and was Manager of Taxation from September 1987 until March 1992. In December 2007, Mr. Goehring announced his intention to retire from his role and duties of Chief Financial Officer in mid 2008. Mr. Goehring's employment with Berry is expected to conclude by the end of 2008. Mr. Goehring is also an Assistant Secretary.

MICHAEL DUGINSKI, 41, has been Executive Vice President and Chief Operating Officer since September 2007. Mr. Duginski served as Executive Vice President of Corporate Development and California from October 2005 to August 2007; he acted as Senior Vice President of Corporate Development from June 2004 through October 2005 and as Vice President of Corporate Development from February 2002 through June 2004. Mr. Duginski, a mechanical engineer, was previously employed by Texaco, Inc. from 1988 to 2002 where his positions included Director of New Business Development, Production Manager and Gas and Power Operations Manager. Mr. Duginski is also an Assistant Secretary.

DAN ANDERSON, 45, has been Vice President of Rocky Mountains Production since October 2005. Mr. Anderson was Rocky Mountains Manager of Engineering from August 2003 through October 2005. Previously, Mr. Anderson served as a Senior Staff Petroleum Engineer with Williams Production RMT from August 2001 through August 2003. He also was a Senior Staff Engineer with Barrett Resources from October 2000 through August 2001.

WALTER B. AYERS, 64, has acted as Vice President of Human Resources since May 2006. Mr. Ayers was previously a private consultant to the energy industry from January 2002 until his employment with us. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000.

GEORGE T. CRAWFORD, 47, has been Vice President of California Production since October 2005. Mr. Crawford served as Vice President of Production from December 2000 through October 2005 and as Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, previously served as the Production Engineering Supervisor for Atlantic Richfield Corp. (ARCO) from 1989 to 1998, with numerous engineering and operational assignments, including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

BRUCE S. KELSO, 52, has been Vice President of Rocky Mountains Exploration since October 2005. Mr. Kelso served as Rocky Mountains Exploration Manager from August 2003 through October 2005. Mr. Kelso, a petroleum geologist, previously acted as 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, 32, has held the position of Controller since March 2007. Mr. Canaday served as Treasurer from December 2004 to February 2007 and as Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and gas industry since 1998 in various finance functions at Chevron and in public accounting. Mr. Canaday is also an Assistant Secretary.

KENNETH A. OLSON, 52, has been Corporate Secretary since December 1985 and was Treasurer from August 1988 until December 2004.

STEVEN B. WILSON, 44, has been Treasurer since March 2007. Mr. Wilson was Controller or Assistant Controller from November 2003 to February 2007. Before joining us in November 2003, he 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. Mr. Wilson is also an Assistant Secretary.

PART II

Item 5. Market for the Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital Stock," are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $.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 2007 and 2006 are shown below:

	2007			2006		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 31.54	$ 27.63	$ .075	$ 39.98	$ 28.60	$ .065
Second Quarter	41.08	30.41	.075	39.00	27.27	.065
Third Quarter	41.06	31.03	.075	35.77	26.07	.095
Fourth Quarter	49.39	39.30	.075	33.69	25.71	.075
Total Dividends Paid			$ .300			$ .300

	February 1, 2008	December 31, 2007	December 31, 2006
Berry's Common Stock closing price per share as reported on NYSE Composite Transaction Reporting System	$ 39.18	$ 44.45	$ 31.01

The number of holders of record of our Common Stock was 547 as of February 1, 2008. There was one Class B Shareholder of record as of February 1, 2008.

Dividends. Our regular annual dividend is currently $.30 per share, payable quarterly in March, June, September and December. 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.

Since our formation in 1985 through December 31, 2007, we have paid dividends on our Common Stock for 73 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 if we have exhausted our restricted payments basket, and up to $10 million in the event we are in a non-payment default.

Equity Compensation Plan Information.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders	3,034,189	$ 24.33	988,798
Equity compensation plans not approved by security holders	none	none	none

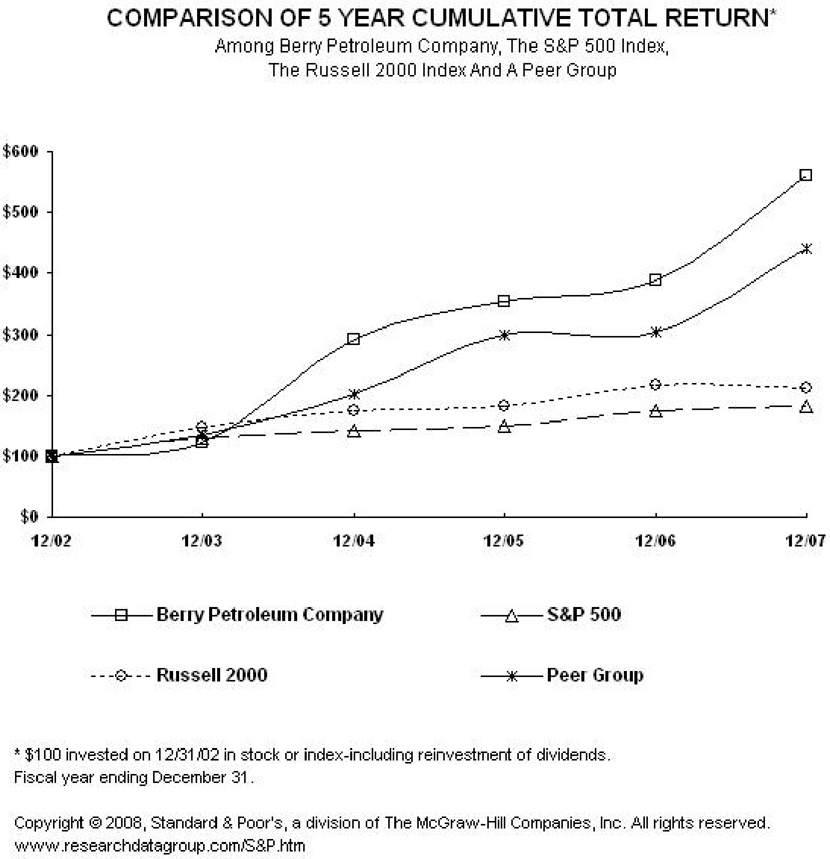
Issuer Purchases of Equity Securities.

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, 2007, we repurchased 818,000 shares in the open market for approximately $25 million. Our repurchase plan expired and no shares were repurchased in 2007.

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, 2002 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index (S&P 500) and a Peer Group, assuming reinvestment of dividends for each measurement period. The information shown is historical and is not necessarily indicative of future performance. The 15 companies which make up the Peer Group are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Encore Acquisition Co., Forest Oil Corp., Petrohawk Energy Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Range Resources Corp., St. Mary Land & Exploration Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp.



	12/02	12/03	12/04	12/05	12/06	12/07
Berry Petroleum Company	100.00	122.01	292.22	353.92	387.58	560.32
S&P 500	100.00	128.68	142.69	149.70	173.34	182.87
Russell 2000	100.00	147.25	174.24	182.18	215.64	212.26
Peer Group	100.00	133.23	201.44	299.34	302.82	439.43

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 Statements of Income and Balance Sheet data included in this table for each of the five years in the period ended December 31, 2007 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data).

	2007	2006	2005	2004	2003
Audited Financial Information					
Sales of oil and gas	$ 467,400	$ 430,497	$ 349,691	$ 226,876	$ 135,848
Sales of electricity	55,619	52,932	55,230	47,644	44,200
Gain on sale of assets	54,173	97	130	410	570
Operating costs - oil and gas production	141,218	117,624	99,066	73,838	57,830
Operating costs - electricity generation	45,980	48,281	55,086	46,191	42,351
Production taxes	17,215	14,674	11,506	6,431	3,097
General and administrative expenses (G&A)	40,210	36,841	21,396	22,504	14,495
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	93,691	67,668	38,150	29,752	17,258
Electricity generation	3,568	3,343	3,260	3,490	3,256
Net income	129,928	107,943	112,356	69,187	32,363
Basic net income per share	2.95	2.46	2.55	1.58	.74
Diluted net income per share	$ 2.89	$ 2.41	$ 2.50	$ 1.54	$ .73
Weighted average number of shares outstanding (basic)	44,075	43,948	44,082	43,788	43,544
Weighted average number of shares outstanding (diluted)	44,906	44,774	44,980	44,940	44,062
Working capital (deficit)	$ (110,350)	$ (116,594)	$ (54,757)	$ (3,840)	$ (3,540)
Total assets	1,452,106	1,198,997	635,051	412,104	340,377
Long-term debt	445,000	390,000	75,000	28,000	50,000
Shareholders' equity	459,974	427,700	334,210	263,086	197,338
Cash dividends per share	.30	.30	.30	.26	.24
Cash flow from operations	248,279	243,229	187,780	124,613	64,825
Exploration and development of oil and gas properties	281,702	265,110	118,718	71,556	41,061
Property/facility acquisitions	56,247	257,840	112,249	2,845	48,579
Additions to vehicles, drilling rigs and other fixed assets	$ 3,565	$ 21,306	$ 11,762	$ 669	$ 494
Unaudited Operating Data					
Oil and gas producing operations (per BOE):					
Average sales price before hedging	$ 49.72	$ 48.38	$ 47.01	$ 33.64	$ 24.48
Average sales price after hedging	47.50	46.67	41.62	30.32	22.52
Average operating costs - oil and gas production	14.38	12.69	11.79	10.09	9.57
Production taxes	1.75	1.58	1.37	.86	.51
G&A	4.09	3.98	2.55	2.99	2.40
DD&A - oil and gas production	$ 9.54	$ 7.30	$ 4.54	$ 3.96	$ 2.86
Production (MBOE)	9,819	9,270	8,401	7,517	6,040
Production (MMWh)	779	757	741	776	767
Total proved reserves (BOE)	169,179	150,262	126,285	109,836	109,920
Standardized measure (1)	$ 2,419,506	$ 1,182,268	$ 1,251,380	$ 686,748	$ 528,220
Year end average BOE price for PV10 purposes	$ 66.27	$ 41.23	$ 48.21	$ 29.87	$ 25.89
Return on average shareholders' equity	29.18%	28.33%	37.63%	31.06%	17.50%
Return on average capital employed	16.01%	18.21%	32.74%	26.29%	15.44%

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

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

Overview. We seek 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 2007.

- Achieved record production which averaged 26,902 BOE/D, up 6% from 2006
- Achieved record cash from operating activities of $248 million, up 2% from 2006
- Achieved record net income of $130 million, up 20% from 2006
- Added 35.4 million BOE of proved reserves before production ending 2007 at a record 169.2 million BOE
- Achieved a reserve replacement rate of 293%
- Expended $341 million of capital expenditures, of which $285 million was for development and $56 million for acquisitions
- Modified steam injection and new well fracturing techniques at N. Midway diatomite, increasing production from existing wells and decreasing the steam oil ratio to six to one
- Started drilling the next 50 well expansion on our N. Midway diatomite asset
- Accomplished a 15 day drilling record on a mesa location and significantly reduced the overall number of days and drilling costs in Piceance
- Completed 47 gross (27 net) Piceance basin operated wells which increased net production to average 10,200 MMcf/D for the full year and 14,600 MMcf/D in the fourth quarter
- Achieved a record production average of 2,400 Bbl/D at Poso Creek by drilling an additional 70 wells
- Drilled 18 horizontal wells at deeper depths at S. Midway to reduce the natural decline and identify additional resource opportunities
- Entered into a long-term crude oil sales contract for our Uinta basin, Utah production
- Entered into a long-term firm transportation contract on the Rockies Express pipeline for our Colorado natural gas production
- Sold Montalvo, California assets with proceeds of approximately $61 million

Notable Items and Expectations for 2008.

- Targeting over 10% net average production growth to achieve between 29,500 and 30,500 BOE/D
- Targeting an increase in 2008 year end proved reserves to between 180 to 190 MMBOE
- Expecting a 2008 capital expenditure program of $295 million to be funded wholly from operating cash flow
- Drilling approximately 120 wells at N. Midway diatomite and targeting production to increase to 2,200 Bbl/D average for the year for an increase of 122%
- Executing a 60 gross (35 net) well drilling program at the Piceance and expecting production to average 21.6 MMcf/D in 2008
- Drilling 28 wells at Poso Creek targeting an average annual production of 3,270 Bbl/D with an average year end exit rate of over 3,500 Bbl/D
- Continuing our appraisal of the Lake Canyon resource potential in the Uinta basin by drilling four Green River wells, three exploratory wells, and participate in deep Wasatch wells

Overview of the Fourth Quarter of 2007. We achieved record average production of 28,023 BOE/D in the fourth quarter of 2007, up 4% from an average of 26,873 BOE/D in the third quarter of 2007. We had net income of $32.3 million, or $.71 per diluted share and net cash from operations was $63.7 million. In December, we entered into a second long-term (ten year) firm transportation contract for our Colorado natural gas production. This contract is for 25,000 MMBtu/D on the REX pipeline and provides us assurance of significant deliverability of our increasing gas production in the Piceance basin. We recognized a $2.9 million pretax gain on the sale of stock (see Note 17 to the financial statements) and we had a pretax impairment charge of $3.3 million associated with our Coyote Flats, Utah asset.

View to 2008. Our challenge for 2008 is to grow our business through improved execution in a rapidly changing price and high cost 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 on our diatomite asset and our properties in the Piceance basin. Our goal is to achieve at least a 10% increase in production and a 10% increase in reserves at a very competitive finding and development cost. Our $295 million capital program is designed to achieve these targets while being funded entirely out of our cash flow from operations. We expect no increase in debt in 2008 unless we are successful in acquiring assets and/or WTI pricing averages below $75 per barrel. We will continue to evaluate acquisition opportunities that fit our growth strategy. Our previously announced plans to proceed with a master limited partnership for certain of our assets is currently on hold due to the unfavorable capital market conditions. We will continue to monitor the economic conditions relevant to a successful offering.

Capital expenditures. Our capital expenditures for 2007 totaled $341 million consisting of $285 million for development and other assets and $56 million for acquisitions. We also capitalized $18 million of interest. We funded these items from $248 million of operating cash flow, $72 million from asset sale proceeds and the balance from additional borrowings. This compares to our total capital expenditures in 2006 of $544 million, which consisted of $258 million of acquisitions, $286 million in development and other assets. Also, we capitalized $9 million of interest in 2006.

Excluding the acquisition of new properties, in 2008 we have a developmental capital program of approximately $295 million which we expect to fund wholly out of operating cash flow and based on WTI pricing to average over $75 per barrel. We are proceeding with this program, but may revise our plans due to lower commodity price expectations, equipment availability, permitting or other factors.

Our 2008 capital program allows us to continue high activity levels and as a result, we are targeting 2008 production to average between 29,500 BOE/D to 30,500 BOE/D. In 2008, we expect production to be approximately 60% heavy oil, 10% light oil and 30% natural gas. We have secured the necessary equipment and are currently meeting permit requirements to achieve the 2008 program.

Development, Exploitation and Exploration Activity. We drilled 442 gross (339 net) wells during 2007, realizing a gross success rate of 98 percent. As of December 31, 2007, we have four rigs drilling on our properties under long-term contracts and have one additional rig that began operating in early 2008.

Drilling Activity. The following table sets forth certain information regarding drilling activities for the year ended December 31, 2007:

	Gross Wells	Net Wells
S. Midway	47	47
N. Midway	49	49
S. Cal	101	101
Piceance	86	29
Uinta	50	48
DJ	109	65
Totals *(1)*	**442**	**339**

(1) Includes 7 gross wells (4.6 net wells) that were dry holes in 2007.

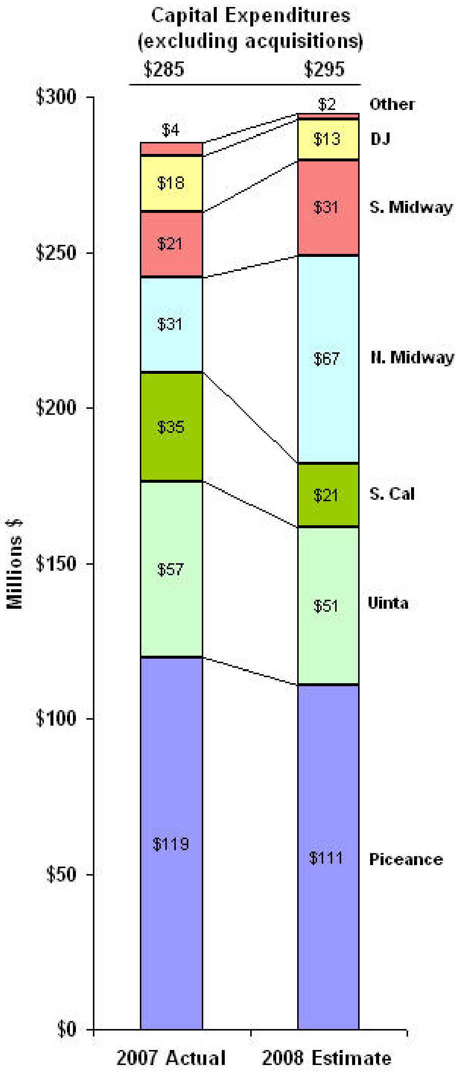
<u>Net Oil and Gas Producing Properties at December 31, 2007.</u>

Name, State	% Average Working Interest	Total Net Acres	Proved Reserves (BOE) in millions	Proved Developed Reserves (BOE) in millions	% of Total Proved Reserves	Proved Undeveloped Reserves (BOE) in millions	% of Total Proved Reserves	Average Depth of Producing Reservoir (feet)
S. Midway, CA	97	2,241	52.4	46.1	27%	6.3	4%	1,700
Uinta, UT	100	36,636	23.5	11.7	7	11.8	7	6,000
S. Cal, CA	100	1,373	26.3	13.3	8	13.0	7	1,200
DJ, CO	47	67,453	21.1	13.4	8	7.7	5	2,600
N. Midway, CA	100	1,898	22.8	12.1	7	10.7	6	1,500
Piceance, CO	32	3,157	23.1	6.2	4	16.9	10	9,300
Totals		112,758	169.2	102.8	61%	66.4	39%	

Our asset base has changed considerably since early 2003. As of December 31, 2007, we had 169.2 MMBOE of proved reserves and have abundant drilling inventories at several of our core areas. Generally, our California assets are mature (our diatomite resource play and our Poso Creek properties are the exceptions) 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.

Properties

We have six asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including diatomite (N. Midway), Southern California including Poso Creek and Placerita (S. Cal), Piceance, Uinta and DJ.



S. Midway - We own and operate working interests in 38 properties, including 23 owned in fee. Production from this field relies on thermal EOR methods, primarily cyclic steaming to place steam effectively into the remaining oil column. This is our most mature thermally enhanced asset.

2007 - Production averaged approximately 9,600 Bbl/D in 2007. We completed 18 horizontal wells at deeper depths which slowed the natural decline of these assets. These wells targeted resource opportunities below our existing horizontal wells and along the edge of the reservoir. Of these infill wells, 25 were drilled to delineate and assess the resource base of a Berry legacy asset at Ethel D.

2008 - Capital is focused on adding 15 horizontal wells below existing horizontal wells, drilling ten vertical steam injection locations to place steam continuously along the edge of the reservoir, and further development at Ethel D including the initiation of a pilot steam flood.

N. Midway - In November 2006, we announced our plans to commence full scale development of our diatomite project in California based on the performance of a two-year pilot program. We expect this development will increase production by up to 8,500 Bbl/D by 2011. 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 development is similar to other California fields.

2007 - Production from the diatomite project averaged approximately 990 Bbl/D in 2007 through implementation of a modified steam injection plan and new well fracturing techniques. Production continued to increase throughout the year primarily as a result of cyclic steaming. We initiated the next phase of our development program in the fairway of the asset in the latter part of the third quarter and expect to be bringing these wells on production in the first quarter of 2008. Installation of the necessary infrastructure, including steam generation equipment and fluid processing facilities, is also in progress.

2008 - Capital is focused on drilling approximately 120 wells, completing major infrastructure upgrades that will support future development, increasing steam injection and further refinement of our thermal recovery techniques including the testing of a horizontal well concept.

S. Cal - We acquired the Poso Creek properties in the San Joaquin Valley basin in early 2003 and have proceeded with a successful thermal EOR redevelopment. In the Placerita field in the Los Angeles basin, we own and operate working interests in thirteen properties, including nine leases and four fee properties. Production relies on thermal recovery methods, primarily steam flooding.

2007 - Poso Creek responded favorably to steam flood injection and our accelerated infill drilling program performed solidly above plan. Production increased to over 2,400 Bbl/D in 2007 from less than 1,000 Bbl/D in 2006. We drilled over 70 wells and installed a third steam generator during the year. We expect continued production improvement as these wells are cyclically steamed, the additional steam flood patterns are brought on line and the balance of the infill wells are drilled and completed.

2008 - Capital is directed at a 28 well drilling program at Poso Creek and further expansion of the steam flood including the installation of the fourth steam generator. The expected year end average exit rate at Poso Creek is over 3,500 Bbl/D.

Piceance - In the first half of 2006, we made two separate acquisitions in the Piceance basin in Colorado, targeting the Williams Fork section of the Mesaverde formation. We acquired a 50% working interest in 6,300 gross acres in the Garden Gulch property and a 5% non-operating working interest on 6,300 gross acres and a net operating working interest of 95% in 4,300 gross acres in the North Parachute Ranch property. We spent $312 million to acquire a majority working interest in several blocks of undeveloped acreage located in the Grand Valley field. We believe we have accumulated a sizable resource base with over 1,000 drilling locations which will allow us to add significant proved reserves over the next five years.

2007 - Production averaged 10,200 MMcf/D in 2007. We operated a four rig drilling program for most of the year and drilled 39 gross (19 net) wells at Garden Gulch and 8 gross (8 net) at North Parachute. Significant progress was made in the last half of 2007 in reducing the days required to drill wells on our Piceance asset. During the fourth quarter drilling days on our mesa wells averaged 16 days on Garden Gulch and 19 days in North Parachute and we are confident we can maintain this efficiency and expect improved economics as a result. Additionally, we continued to expand the infrastructure needed to support our operations, and have acquired additional firm transportation for future sales out of this region.

2008 - We plan to operate a four rig program with our capital directed at drilling 46 gross (23 net) wells in Garden Gulch and 13 gross (12 net) wells in North Parachute, constructing the necessary expansion of our gathering and water handling facilities, and continued expansion of our road infrastructure including the construction of a new access road to our mesa acreage on the Old Mountain block of North Parachute.

Uinta - The Brundage Canyon leasehold in Duchesne County, northeastern Utah consists of approximately 26,000 undeveloped gross acres which include federal, tribal and private leases. We are targeting the Green River formation that produces both light oil and natural gas. Along with an industry partner, we hold a 169,000 gross acre block in the Lake Canyon project, which is located immediately west of our Brundage Canyon producing properties. We will drill and operate the shallow wells, targeting 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 that will 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.

2007 - During 2007 the refinery capacity for our black wax crude improved from the constraints experienced during 2006. In February 2007, we signed a six year oil contract with a refiner, allowing us to deliver 3,200 Bbl/D starting in July 2007 with up to 5,000 Bbl/D through June 30, 2013 upon the certified completion of its refinery upgrade expected in the first half of 2008. Deliveries under this contract has allowed us to sell all of our crude oil production in the Uinta Basin and has stabilized our realized sales price and reduced transportation costs.

In 2007 we drilled 50 gross (48 net) wells in the Uinta project which included 39 gross (39 net) wells at Brundage Canyon, six wells testing the Ashley Forest acreage to the south, and five wells at Lake Canyon targeting the Green River formation. In addition, we participated in the drilling of one Lake Canyon Wasatch well with our industry partner. Average daily production during 2007 from all Uinta basin assets was approximately 5,700 net BOE/D. At the end of 2007, we had one drilling rig operating in the basin.

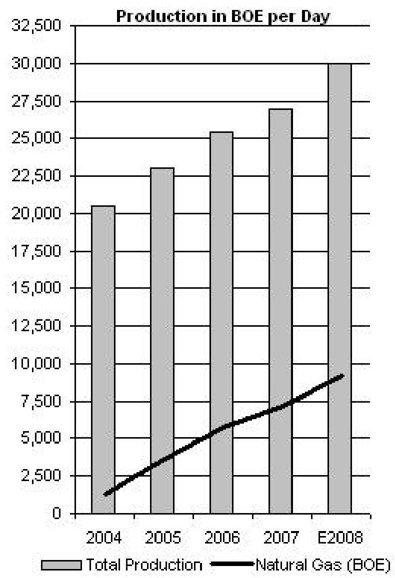
2008 - Capital at Brundage Canyon is directed at drilling 44 additional wells targeting high graded locations across the field and further delineation wells on our Ashley Forest acreage to the south. We are also evaluating the feasibility of waterflooding Brundage Canyon to further improve recovery and anticipate installing a waterflood pilot late this year. The Ashley Forest EIS continues to progress and we anticipate approval in the first quarter of 2009. Capital at Lake Canyon is directed at the continued appraisal of our acreage with the drilling of four wells targeting the Green River, and three exploratory wells targeting both Green River and Wasatch potential and to participate with our industry partner in deep Wasatch wells.

DJ - In 2005, we made three acquisitions for approximately $111 million establishing a core area in the Niobrara gas producing assets in Yuma County in northeastern Colorado, where we have a working interest averaging approximately 52%. This acquisition in the Tri-State region (Eastern Colorado, western Kansas and southwestern Nebraska) totaled approximately 100,000 net producing acres and 315,000 net total acres. Our other two acquisitions in the region consisted of undeveloped prospective acreage where our working interests range from 40% to 50%. Our Yuma County Niobrara projects provide sustainable and steady cash flow resulting from low capital development costs, modest production declines and long-life reserves.

2007 - We drilled over 100 successful Niobrara development wells in Yuma County adding production from both proved undeveloped and probable reserves. We continued to expand our compression and gathering infrastructure and acquired an additional 37 square miles of 3-D seismic data in Colorado. Average daily production in the DJ in 2007 was 18,700 net MMcf/D. We determined that our position in a portion of the Tri-State acreage was not sizable enough for us to continue with its development, thus we wrote down $4.6 million of our Tri-State acreage carrying value in connection with the sale of these properties, which we believe approximates fair value as of December 31, 2007 based on available information.

2008 - Capital is directed at drilling 86 gross (37 net) Niobrara wells, installing pumping units on 145 gross (45 net) wells, and installing associated compression, gathering and water disposal facilities. Over 75 square miles of 3-D seismic acquisition in Yuma County is planned for early 2008.

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.



Revenues. Approximately 80% 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 20% of our revenues are primarily derived from electricity sales from cogeneration facilities which supply approximately 35% 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.

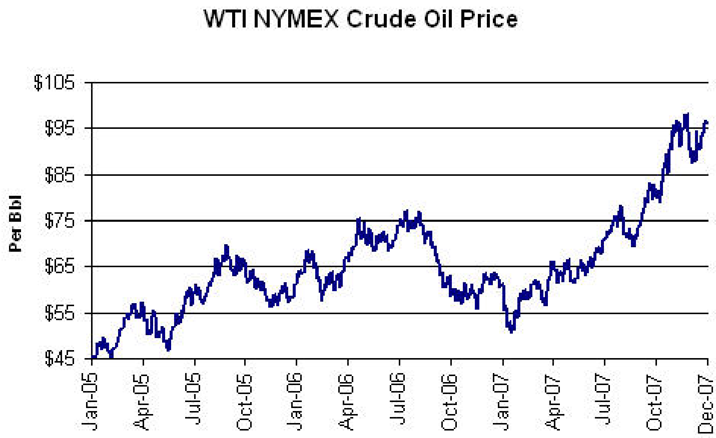
Sales of oil and gas were up 9% in 2007 compared to 2006 and up 23% from 2005. This improvement was due to an overall increase in both oil and gas production levels and increased oil prices. Improvements in production volume reflect the successful results of capital investments. While improvement in oil prices during 2007 were due to a tighter supply and demand balance, natural gas prices decreased as a result of the impact of high storage levels and mild weather conditions in the U.S. Oil and natural gas prices contributed roughly 3% of the revenue increase and the increase in production volumes contributed the other 6%. Approximately 70% of our oil and gas sales volumes in 2007 were crude oil, with 83% 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 $15 million, $21 million and $41 million in 2007, 2006 and 2005, respectively.

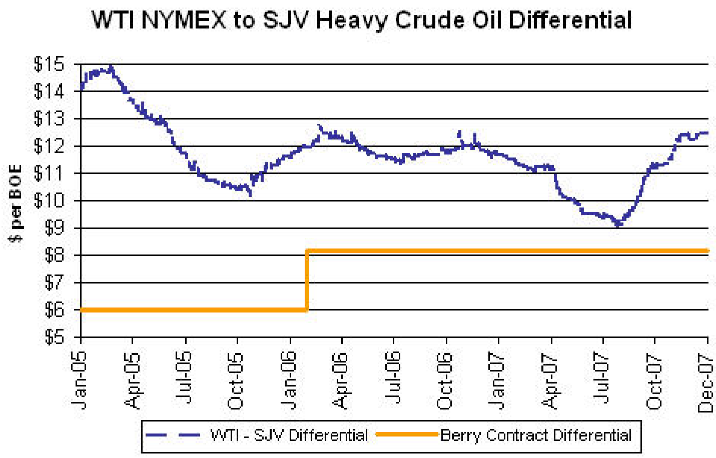
The following companywide results are in millions (except per share data) for the years ended December 31:

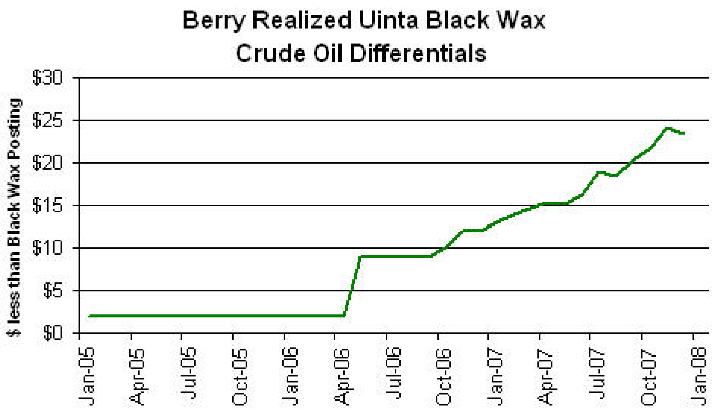
	2007	2006	2005
Sales of oil	$ 385	$ 360	$ 289
Sales of gas	82	70	61
Total sales of oil and gas	$ 467	$ 430	$ 350
Sales of electricity	56	53	55
Gain on sale of assets	54	1	-
Interest and other income, net	6	2	2
Total revenues and other income	$ 583	$ 486	$ 407
Net income	$ 130	$ 108	$ 112
Earnings per share (diluted)	$ 2.89	$ 2.41	$ 2.50

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

	December 31, 2007	December 31, 2006	September 30, 2007
Sales of oil	$ 109	$ 84	$ 100
Sales of gas	24	18	19
Total sales of oil and gas	$ 133	$ 102	$ 119
Sales of electricity	15	13	12
Gain on sale of assets	2	-	1
Interest and other income, net	3	1	1
Total revenues and other income	$ 153	$ 116	$ 133
Net income	$ 32	$ 19	$ 27
Net income per share (diluted)	$ .71	$ .43	$ .60





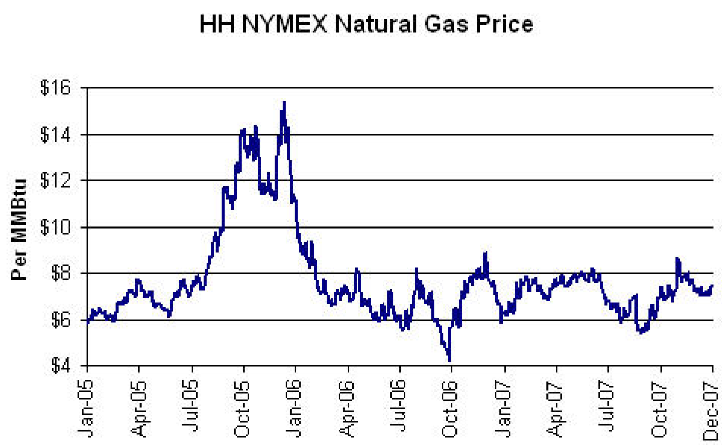


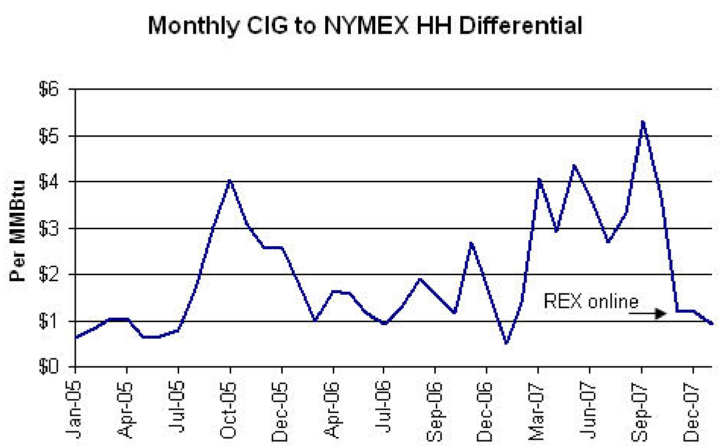
Oil Contracts. See Item 1 Business.

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:

	2007	%	2006	%	2005	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	16,170	60	15,972	63	16,063	70
Light Oil Production (Bbl/D)	3,583	13	3,707	15	3,336	14
Total Oil Production (Bbl/D)	19,753	73	19,679	78	19,399	84
Natural Gas Production (Mcf/D)	42,895	27	34,317	22	21,696	16
Total (BOE/D)	26,902	100	25,398	100	23,015	100
Percentage increase from prior year	6%		10%		12%	
Per BOE:						
Average sales price before hedging	$ 49.72		$ 48.38		$ 47.01	
Average sales price after hedging	47.50		46.67		41.62	
Oil, per Bbl:						
Average WTI price	$ 72.41		$ 66.25		$ 56.70	
Price sensitive royalties	(5.03)		(5.13)		(4.42)	
Gravity differential and other	(9.53)		(8.20)		(5.22)	
Crude oil hedges	(4.61)		(2.37)		(6.21)	
Average oil sales price after hedging	$ 53.24		$ 50.55		$ 40.85	
Natural gas price:						
Average Henry Hub price per MMBtu	$ 7.12		$ 6.97		$ 9.01	
Conversion to Mcf	.34		.33		.43	
Natural gas hedges	.74		.09		(.16)	
Location, quality differentials and other	(2.93)		(1.82)		(1.65)	
Average gas sales price after hedging	$ 5.27		$ 5.57		$ 7.63	





The following table is for the three months ended:

	December 31, 2007	%	December 31, 2006	%	September 30, 2007	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	16,595	59	16,833	63	15,806	59
Light Oil Production (Bbl/D)	3,395	12	3,363	13	3,675	14
Total Oil Production (Bbl/D)	19,990	71	20,196	76	19,481	73
Natural Gas Production (Mcf/D)	48,196	29	40,157	24	44,346	27
Total (BOE/D)	28,023	100	26,889	100	26,873	100
Per BOE:						
Average sales price before hedging	$ 60.38		$ 41.53		$ 49.35	
Average sales price after hedging	52.32		42.00		47.93	
Oil, per Bbl:						
Average WTI price	$ 90.50		$ 60.17		$ 75.15	
Price sensitive royalties	(6.68)		(4.28)		(5.50)	
Gravity differential and other	(9.92)		(9.06)		(9.56)	
Crude oil hedges	(13.57)		(.01)		(4.37)	
Average oil sales price after hedging	$ 60.33		$ 46.82		$ 55.72	
Natural gas price:						
Average Henry Hub price per MMBtu	$ 7.39		$ 7.24		$ 6.24	
Conversion to Mcf	.35		.34		.31	
Natural gas hedges	.91		.31		1.07	
Location, quality differentials and other	(3.21)		(3.23)		(3.06)	
Average gas sales price after hedging	$ 5.44		$ 4.66		$ 4.56	

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 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. Revenues were up and operating costs were down in the year ended 2007 from the year ended 2006 due to 2% higher electricity prices and 6% lower natural gas prices, respectively. In 2007, our electricity operations improved partially from the lower cost of our firm transportation natural gas we purchased. We purchase and transport 12,000 average MMBtu/D on the Kern River Pipeline under our firm transportation contract and use this gas to produce conventional and cogeneration steam in the Midway-Sunset field. The differential between Rocky Mountain gas prices and Southern California Border prices increased during 2007 compared to 2006 allowing us to purchase a portion of our gas at prices less than the Southern California Border price. As our electricity revenue are linked to Southern California Border prices, the fuel we purchased at lower Rocky Mountain prices was the primary contributor to the increase in our electricity margin in 2007.

We purchased approximately 38 MMBtu/D as fuel for use in our cogeneration facilities in the year ended December 31, 2007. On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes prospectively the way SRAC energy prices will be determined for existing and new SO contracts and revises the capacity prices paid under current SO1 contracts. Based on our preliminary analysis, we do not believe that the proposed pricing changes will materially affect us in 2008. The following table is for the years ended December 31:

	2007	2006	2005
Electricity			
Revenues (in millions)	$ 55.6	$ 52.9	$ 55.2
Operating costs (in millions)	$ 46.0	$ 48.3	$ 55.1
Decrease to total oil and gas operating expenses per barrel	$ .98	$ .50	$ .02
Electric power produced - MWh/D	2,133	2,074	2,030
Electric power sold - MWh/D	1,932	1,867	1,834
Average sales price/MWh (no hedging was in place)	$ 78.62	$ 77.13	$ 82.73
Fuel gas cost/MMBtu (including transportation)	$ 6.08	$ 6.44	$ 7.72

The following table is for the three months ended:

	December 31, 2007	December 31, 2006	September 30, 2007
Electricity			
Revenues (in millions)	$ 14.9	$ 13.5	$ 12.3
Operating costs (in millions)	$ 11.0	$ 12.1	$ 9.8
Electric power produced - MWh/D	2,099	2,093	2,257
Electric power sold - MWh/D	2,077	1,861	2,077
Average sales price/MWh	$ 78.98	$ 75.05	$ 71.28
Fuel gas cost/MMBtu (including transportation)	$ 6.10	$ 6.44	$ 5.07

Royalties. A price-sensitive royalty burdens certain of our S. Midway properties which produced approximately 2,900 BOE/D in 2007. This royalty is 75% of the amount of the heavy oil posted price above a base price which was $15.79 in 2007. This base price escalates at 2% annually, thus the threshold price is $16.11 per barrel in 2008. Liabilities payable for these royalties were $36 million, $36 million and $29 million in the years ended December 31, 2007, 2006 and 2005, respectively. Because our interest in the revenue varies according to crude prices, the continuing development on this property will depend on its future profitability.

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)		
	2007	2006	Change	2007	2006	Change
Operating costs - oil and gas production	$ 14.38	$ 12.69	13 %	$ 141,218	$ 117,624	20%
Production taxes	1.75	1.58	11 %	17,215	14,674	17%
DD&A - oil and gas production	9.54	7.30	31 %	93,691	67,668	38%
G&A	4.09	3.98	3 %	40,210	36,841	9%
Interest expense	1.76	1.05	68 %	17,287	10,247	69%
Total	$ 31.52	$ 26.60	18 %	$ 309,621	$ 247,054	25%

Our total operating costs, production taxes, G&A and interest expenses for 2007, stated on a unit-of-production basis, increased 18% over 2006. The changes were primarily related to the following items:

- Operating costs: Our operating costs increased primarily due to higher contract services and labor costs, higher compression, gathering, and dehydration costs and higher steam costs resulting from higher volumes of injected steam. The following table presents steam information:

	2007	2006	Change
Average volume of steam injected (Bbl/D)	87,990	81,246	8%
Fuel gas cost/MMBtu (including transportation)	$ 6.08	$ 6.44	(6%)

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 2008 of approximately 110,000 BSPD or a 25% increase compared to 2007.

- 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 field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. We expect production taxes to track oil and gas prices generally.

- Depreciation, depletion and amortization: DD&A increased per BOE in 2007 by 31% from 2006. Over the past year this increase has resulted from an increase in capital spending in fields with higher drilling and leasehold acquisition costs, which is in line with our expectations. Additionally, DD&A may continue to trend higher as a certain portion of our interest cost related to our Piceance basin acquisitions is capitalized into the basis of the assets. We anticipate a portion will continue to be capitalized over the next several years until our probable reserves have been recategorized to proved reserves.

- General and administrative: Approximately 70% of our G&A is related to compensation. The primary reason for the increase in G&A during 2007 was an 8% increase in employee headcount to accelerate the development of our assets and our competitive compensation practices to attract and retain our personnel.

- Interest expense: Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, was $459 million at December 31, 2007 compared to $406 million at December 31, 2006. Average borrowings in 2007 increased primarily due to our final payment on our Piceance acquisition. For the year ended December 31, 2007, $18 million of interest cost has been capitalized and we expect to capitalize approximately $20 million of interest cost during the full year of 2008.

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

	Amount per BOE			Amount (in thousands)		
	December 31, 2007	December 31, 2006	September 30, 2007	December 31, 2007	December 31, 2006	September 30, 2007
Operating costs - oil and gas production	$ 14.70	$ 13.69	$ 13.75	$ 37,889	$ 33,804	$ 33,995
Production taxes	1.91	1.15	1.76	4,918	2,840	4,344
DD&A - oil and gas production	10.94	8.24	9.45	28,212	20,335	23,356
G&A	4.24	4.55	3.78	10,918	11,231	9,333
Interest expense	1.43	1.27	1.75	3,693	3,503	4,326
Total	$ 33.22	$ 28.90	$ 30.49	$ 85,630	$ 71,713	$ 75,354

	December 31, 2007	December 31, 2006	Change	September 30, 2007	Change
Average volume of steam injected (Bbl/D)	90,894	85,349	6%	88,711	2 %
Fuel gas cost/MMBtu (including transportation)	$ 6.10	$ 6.05	1%	$ 5.07	20%

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 and as a result of the increased steam injection, our crude oil production on these properties increased. The cost of our steaming operations 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 (including transportation)	$ 6.44	$ 7.72	(17%)

- Production taxes: During 2006 our production taxes increased as a result of higher assessed values on our properties, increased production and higher investment in mineral interests.

- Depreciation, depletion and amortization: DD&A increased per BOE in 2006 due to large increases in capital spending since 2005 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 experienced 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% in 2006 as we added an important new core asset into our portfolio and as we strengthened our talent base. 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 expenditures 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. For the year ended December 31, 2006, $9.3 million was capitalized.

Estimated 2008 Oil and Gas Operating, G&A and Interest Expenses. We estimate our 2008 production volume will range between 29,500 BOE/D and 30,500 BOE/D. Based on WTI of $75 and NYMEX HH of $7.50 MMBtu, we expect our expenses to be within the following ranges:

	Amount per BOE		
	Anticipated range in 2008	2007	2006
Operating costs-oil and gas production (1)	$ 16.00 to 17.50	$ 14.38	$ 12.69
Production taxes	1.75 to 2.25	1.75	1.58
DD&A	9.75 to 10.75	9.54	7.30
G&A	4.00 to 4.50	4.09	3.98
Interest expense	1.25 to 1.50	1.76	1.05
Total	$ 32.75 to 36.50	$ 31.52	$ 26.60

(1) We expect operating costs to increase in 2008 as compared to 2007 due to higher projected natural gas costs.

Dry hole, abandonment, impairment and exploration. In 2007 we had dry hole, abandonment and impairment charges of $13.7 million consisting primarily of a $4.6 million writedown of a portion of our Tri-State acreage in connection with the current and pending sale of these properties, a $3.3 million impairment of our Coyote Flats prospect to reflect its fair value in conjunction with the preparation of our year end reserve estimates, a $2.9 million writedown of our Bakken properties sold in September 2007, and other dry hole charges of $2.2 million. We incurred exploration costs of $.7 million in 2007 compared to $3.8 million and $3.6 million in 2006 and 2005, respectively. These costs consist primarily of geological and geophysical costs in the DJ basin. We are projecting geological and geophysical costs in 2008 of between $2 million and $3 million.

In 2006 we incurred $8.3 million of dry hole, abandonment and impairment consisting 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, four wells in Bakken and four wells in the DJ basin for $1.5 million. For the year ended 2005, costs of $5.7 million were incurred on the following: one exploratory well on the Coyote Flats prospect, one well on the Midway-Sunset property, two exploratory wells on northern Brundage Canyon in the Uinta basin, and impairment of $2.5 million on the remaining carrying value of our Illinois and eastern Kansas prospective CBM acreage were charged to expense.

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. We don’t expect to generate the EOR tax credit for 2008, due to current oil prices. As of December 31, 2007 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 purposes, respectively.

We experienced an effective tax rate of 38%, 39% and 31% in 2007, 2006 and 2005, respectively. The rate is lower than our combined federal and state statutory tax rate of 40% primarily due to certain business incentives. In anticipation of the continued full EOR credit phase out in 2008, we expect our effective tax rate to approximate 38%, given the current oil price environment. See Note 9 to the financial statements for further information.

Commodity derivatives. In March 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 of $4.8 million represented the change in fair market value over the life of the contract, resulting from an increase in natural gas prices from the date of the derivative to March 31, 2006. In May 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 Statements of Income in 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 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 that we believe the development potential will not be meaningful to us as a whole. We divested several assets in 2007. Proceeds from these sales contributed to the funding of our capital program. Net oil and gas properties and equipment classified as held for sale is $1.4 million as of December 31, 2007 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 revisions of previous estimates, 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 market value. We believe our calculation of this measure is substantially similar to how other companies compute the 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, production rates and operating expenses have been the primary reason for changes in our cash flow from operating activities. In 2006, we revised our senior unsecured revolving credit facility to increase our maximum credit amount under the facility to $750 million and in 2007 we increased our borrowing base from $500 million to $550 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, 2007, we had total borrowings under the senior unsecured revolving credit facility and senior unsecured money market line of credit of $259 million and $200 million under our senior subordinated notes. See Item 7A Quantitative and Qualitative Disclosures About Market Risk for discussion of interest rate sensitivity.

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 or significant changes in cash flow. Excess cash generated from operations is expected to be applied toward acquisitions, debt reduction or other corporate purposes.

In 2008, we have a capital program of approximately $295 million, excluding acquisitions. Our 2008 expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2008, we plan to invest approximately $118 million, or 40%, in our heavy crude oil assets, and $175 million, or 59%, in our natural gas and light oil assets. Approximately two-thirds 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 one-third is for the development of our proved undeveloped reserves and facility costs.

Dividends. 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 2007 (see graphs on pages 32 and 33) and we increased production by 6%.

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 May 2007, we sold our non-core West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million and we recognized a $52 million pretax gain on the sale, including post closing adjustments. Production from the property was approximately 700 BOE/D, which is less than 3% of average 2007 production and, as of December 31, 2006, the property had 7 million BOE of proved reserves, which is less than 5% of the 2006 year end total of 150 million BOE. Separately, during the second quarter we paid the third and final installment of approximately $54 million for the North Parachute Ranch property located in the Piceance basin.

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):

	2007	2006	Change
Average production (BOE/D)	26,902	25,398	6%
Average oil and gas sales prices, per BOE after hedging	$ 47.50	$ 46.67	2%
Net cash provided by operating activities	$ 248	$ 243	2%
Working capital	$ (110)	$ (117)	6%
Sales of oil and gas	$ 467	$ 430	9%
Total debt	$ 459	$ 406	13%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 338	$ 523	(35%)
Dividends paid	$ 13.3	$ 13.2	1%

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, 2007	December 31, 2006	Change	September 30, 2007	Change
Average production (BOE/D)	28,023	26,889	4%	26,873	4%
Average oil and gas sales prices, per BOE after hedging	$ 52.31	$ 42.00	25%	$ 47.93	9%
Net cash provided by operating activities	$ 64	$ 58	10%	$ 93	(31%)
Working capital	$ (110)	$ (117)	6%	$ (91)	(21%)
Sales of oil and gas	$ 133	$ 102	30%	$ 119	12%
Total debt	$ 459	$ 406	13%	$ 440	4%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 76	$ 127	(40%)	$ 63	21%
Dividends paid	$ 3.3	$ 3.3	-%	$ 3.4	(3%)

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, 2007 are as follows (in thousands):

	Total	2008	2009	2010	2011	2012	Thereafter
Long-term debt and interest	$ 649,658	$ 36,336	$ 31,029	$ 31,029	$ 268,764	$ 16,500	$ 266,000
Abandonment obligations	36,426	1,456	1,456	1,456	1,456	1,456	29,146
Operating lease obligations	12,407	1,690	1,374	1,357	1,357	1,357	5,272
Drilling and rig obligations	74,749	23,559	18,817	7,353	25,020	-	-
Firm natural gas transportation contracts	173,243	15,206	19,545	19,544	19,545	19,054	80,349
Total	$ 946,483	$ 78,247	$ 72,221	$ 60,739	$ 316,142	$ 38,367	$ 380,767

Long-term debt and interest - Our credit facility borrowings and related interest of approximately 5.9% can be paid before its maturity date without significant penalty. 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, 2007, 2006 and 2005 was $1.5 million, $1 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 obligations - Starting in 2006, we began to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the four year contract. Our minimum obligation under our exploration and development agreement is $9.6 million, and as of December 31, 2007 the remaining obligation is $5.4 million. Also included above, under our June 2006 joint venture agreement in the Piceance basin we are required to have 120 wells drilled by February 2011 to avoid penalties of $.2 million per well or a maximum of $24 million. As of December 31, 2007 we have drilled 12 of these wells.

Drilling rig obligations - 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 have seven long-term transportation contracts on four different pipelines to provide us with physical access to move gas from our producing areas to various markets.

Other Obligations. We adopted the provisions of FIN No. 48 on January 1, 2007 and recognized no material adjustment to retained earnings. As of December 31, 2007, we had a gross liability for uncertain tax benefits of $12 million of which $9.1 million, if recognized, would affect the effective tax rate. We recognize potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. As of December 31, 2007, we had accrued approximately $1.1 million of interest related to our uncertain tax positions. Due to the uncertainty about the periods in which examinations will be completed and limited information related to current audits, we are not able to make reasonably reliable estimates of the periods in which cash settlements will occur with taxing authorities for the noncurrent liabilities.

On February 27, 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D on July 1, 2007. Upon completion of its refinery expansion in Salt Lake City, which is expected in the first half of 2008, the refiner will increase its total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI, which was near the posted price at the contract's starting date.

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, or when current events or circumstances indicate that carrying amount may not be recoverable, by comparing the future undiscounted net revenue 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 changes 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* as interpreted by FIN 48, *Accounting for Uncertainty in 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. We may generate EOR tax credits from the production of our heavy crude oil in California which may result in a deferred tax asset. We 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. FIN 48 clarifies the accounting for income taxes by prescribing the minimum recognition threshold an uncertain tax position is required to meet before tax benefits associated with such uncertain tax positions are recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 excludes income taxes from the scope of SFAS No. 5, *Accounting for Contingencies*. FIN 48 also requires that amounts recognized in the Balance Sheet related to uncertain tax positions be classified as a current or noncurrent liability, based upon the expected timing of the payment to a taxing authority.

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 to determine 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, and 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 influence the decision of management as to 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 may 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 the 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 acquired and liabilities assumed 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 added into the depreciable base of our assets and is expensed on a units of production basis over the 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 principles, 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 became effective for our fiscal year beginning January 1, 2007. While there was no impact on our financial statements as of December 31, 2007, 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 Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*, *Accounting for Income Taxes*. 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. We adopted this interpretation in the first quarter of 2007. See Note 9.

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 effect this statement may have on our financial statements. . However, we do not believe that the implementation of SFAS 157 will have a material impact 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* was issued by the Securities and Exchange Commission. 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 our results of 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 do not expect this Statement to have a material effect on our financial statements.

In April 2007, the FASB issued a FASB Staff Position to amend FASB Interpretation 39, *Offsetting of Amounts Related to Certain Contracts*. FIN 39-1 states that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with paragraph 10 of Interpretation 39. FIN 39-1 will become effective for our fiscal year beginning January 1, 2008 and will have no effect on our financial statements as we do not post collateral under our hedging agreements.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements*. SFAS 160 was issued to establish accounting and reporting standards for the noncontrolling interest in a subsidiary (formerly called minority interests) and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. We do not expect the adoption of SFAS 160 to have a material effect on our financial statements and related disclosures. The effective date of this Statement is the same as that of the related Statement 141(R).

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*, which improves the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The Statement also recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply it before that date. We may experience a financial statement impact depending on the nature and extent of any new business combinations entered into after the effective date of SFAS No. 141(R).

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 to protect our profitability and the economics of our development plans, we enter into crude oil and natural gas hedge contracts from time to time. 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 CIG, PEPL and Questar index prices, respectively.

The following table summarizes our hedge positions as of December 31, 2007:

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 2008	1,000	$70.00 / $76.70	1st Quarter 2008	16,000	$1.74
Full year 2008	10,000	$47.50 / $70.00	2nd Quarter 2008	17,000	$1.43
Full year 2009	10,000	$47.50 / $70.00	3rd Quarter 2008	19,000	$1.40
Full year 2009	295	$80.00 / $91.00	4th Quarter 2008	21,000	$1.46
Full year 2010	1,000	$60.00 / $80.00			
Full year 2010	1,000	$55.00 / $76.20	**Natural Gas Sales (NYMEX HH) Swaps**		
Full year 2010	1,000	$55.00 / $77.75	1st Quarter 2008	16,200	$8.04
Full year 2010	1,000	$55.00 / $77.70	2nd Quarter 2008	16,200	$8.04
Full year 2010	1,000	$55.00 / $83.10	3rd Quarter 2008	16,200	$8.04
Full year 2010	1,000	$60.00 / $75.00	4th Quarter 2008	16,200	$8.04
Full year 2010	1,000	$65.15 / $75.00			
Full year 2010	1,000	$65.50 / $78.50	**Natural Gas Sales (NYMEX HH) Collars**		Floor/Ceiling Prices
Full year 2010	280	$80.00 / $90.00	2nd Quarter 2008	800	$7.50 / $8.40
Full year 2011	270	$80.00 / $90.00	3rd Quarter 2008	2,800	$7.50 / $8.50
			4th Quarter 2008	4,800	$8.00 / $9.50
Crude Oil Sales (NYMEX WTI) Swaps					
Full year 2008	260	$74.00			
Full year 2008	335	$92.00			
Full year 2009	240	$71.50			

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 basis 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 basis hedge positions.

As of February 26, 2008, we entered into gas swaps for 15,400 MMBtu/D at $8.50 for the full year of 2009 and basis swaps on the same volumes for average prices of $1.17, $1.12, $.97 and $1.05 for the first, second, third and fourth quarters of 2009, respectively.

The collar strike prices will allow us to protect a significant portion of our future cash flow if 1) oil prices decline below our floor prices which range from $47.50 to $80.00 per barrel while still participating in any oil price increase up to the ceiling prices which range from $70.00 to $91.00 per barrel on the volumes indicated above, and if 2) gas prices decline below our floor prices which range from $7.50 to $8.00 per MMBtu while still participating in any gas price increase up to the ceiling prices, which range from $8.40 to $9.50 per MMBtu on the respective volumes. 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, including certain basis differentials. 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 (Loss). 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) in March 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 Statements of Income 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, in June 2006 and July 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, 2007, Accumulated Other Comprehensive Loss, net of income taxes, consisted of $121 million of unrealized losses from our crude oil and natural gas hedges. Deferred net losses recorded in Accumulated Other Comprehensive Loss at December 31, 2007 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.

	2007	2006	2005
Net reduction of sales of oil and gas revenue due to hedging activities (in millions)	$ 21.8	$ 15.7	$ 45.3
Net reduction of cost of gas due to hedging activities (in millions)	$ -	$ 1.6	$ 5.0
Net reduction in revenue per BOE due to hedging activities	$ 2.21	$ 1.71	$ 5.39

Based on NYMEX futures prices as of December 31, 2007 (WTI $88.34; HH $7.81), 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:

	12/31/07 NYMEX Futures	Impact of percent change in futures prices on earnings			
		-20%	-10%	+10%	+20%
Average WTI Futures Price (2008 - 2011)	$ 88.34	$ 70.67	$ 79.50	$ 97.17	$ 106.00
Average HH Futures Price (2008)	7.81	6.24	7.03	8.59	9.37
Crude Oil gain/(loss) (in millions)	(186.5)	(15.8)	(92.0)	(285.8)	(386.2)
Natural Gas gain/(loss) (in millions)	.5	10.7	5.5	(4.1)	(9.2)
Total	$ (186.0)	$ (5.1)	$ (86.5)	$ (289.9)	$ (395.4)
Net pretax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2008 (WTI $93.71; HH $7.81)	$ (94.3)	$ (5.4)	$ (49.6)	$ (138.6)	$ (183.3)
2009 (WTI $88.39)	(68.6)	(2.0)	(35.5)	(102.3)	(136.3)
2010 (WTI $85.83)	(23.1)	1.2	(1.7)	(48.7)	(74.6)
2011 (WTI $85.41)	-	1.1	.3	(.3)	(1.2)
Total	$ (186.0)	$ (5.1)	$ (86.5)	$ (289.9)	$ (395.4)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 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, 2007 and 2006 was $445 million and $390 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 2007 credit facility borrowings, a 1% change in interest rates would have a $1 million after tax impact on our financial statements.

Item 8. Financial Statements and Supplementary Data

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:

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, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 of the consolidated financial statements, during the year ended December 31, 2007, Berry Petroleum Company changed the manner in which it accounts for uncertain tax positions.

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 26, 2008

BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2007 and 2006
(In Thousands, Except Share Information)

ASSETS	2007	2006
Current assets:		
Cash and cash equivalents	$ 316	$ 416
Short-term investments	58	665
Accounts receivable	117,038	67,905
Deferred income taxes	28,547	-
Fair value of derivatives	2,109	7,349
Assets held for sale	1,394	8,870
Prepaid expenses and other	11,557	13,604
Total current assets	161,019	98,809
Oil and gas properties (successful efforts basis), buildings and equipment, net	1,275,091	1,080,631
Fair value of derivatives	-	2,356
Other assets	15,996	17,201
	$ 1,452,106	$ 1,198,997
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 90,354	$ 69,914
Property acquisition payable	-	54,400
Revenue and royalties payable	47,181	45,845
Accrued liabilities	21,653	20,415
Line of credit	14,300	16,000
Income taxes payable	2,591	-
Deferred income taxes	-	745
Other current liabilities	-	-
Fair value of derivatives	95,290	8,084
Total current liabilities	271,369	215,403
Long-term liabilities:		
Deferred income taxes	128,824	103,515
Long-term debt	445,000	390,000
Abandonment obligation	36,426	26,135
Unearned revenue	398	1,437
Other long-term liabilities	1,657	-
Fair value of derivatives	108,458	34,807
	720,763	555,894
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; 42,583,002 shares issued and outstanding (42,098,551 in 2006)	425	421
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899) (1,797,784 in 2006)	18	18
Capital in excess of par value	66,590	50,166
Accumulated other comprehensive loss	(120,704)	(19,977)
Retained earnings	513,645	397,072
Total shareholders' equity	459,974	427,700
	$ 1,452,106	$ 1,198,997

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

BERRY PETROLEUM COMPANY
Statements of Income
Years ended December 31, 2007, 2006 and 2005
(In Thousands, Except Per Share Data)

	2007	2006	2005
REVENUES			
Sales of oil and gas	$ 467,400	$ 430,497	$ 349,691
Sales of electricity	55,619	52,932	55,230
Gain on sale of assets	54,173	97	130
Interest and other income, net	6,265	2,812	1,674
	583,457	486,338	406,725
EXPENSES			
Operating costs - oil and gas production	141,218	117,624	99,066
Operating costs - electricity generation	45,980	48,281	55,086
Production taxes	17,215	14,674	11,506
Depreciation, depletion & amortization - oil and gas production	93,691	67,668	38,150
Depreciation, depletion & amortization - electricity generation	3,568	3,343	3,260
General and administrative	40,210	36,841	21,396
Interest	17,287	10,247	6,048
Commodity derivatives	-	(736)	-
Dry hole, abandonment, impairment and exploration	13,657	12,009	9,354
	372,826	309,951	243,866
Income before income taxes	210,631	176,387	162,859
Provision for income taxes	80,703	68,444	50,503
Net income	$ 129,928	$ 107,943	$ 112, 356
Basic net income per share	$ 2.95	$ 2.46	$ 2.55
Diluted net income per share	$ 2.89	$ 2.41	$ 2.50
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	44,075	43,948	44,082
Effect of dilutive securities:			
Stock options	604	723	780
Other	227	103	118
Weighted average number of shares of capital stock used to calculate diluted net income per share	44,906	44,774	44,980

Statements of Comprehensive Income
Years Ended December 31, 2007, 2006 and 2005
(In Thousands)

	2007	2006	2005
Net income	$ 129,928	$ 107,943	$ 112,356
Unrealized gains (losses) on derivatives, net of income taxes of ($66,627), $7,647, and ($16,677), respectively	(99,941)	11,471	(25,015)
Reclassification of realized gains (losses) on derivatives included in net income, net of income taxes of ($524), ($4,712) and $1,081, respectively	(786)	(7,068)	1,622
Comprehensive income	$ 29,201	$ 112,346	$ 88,963

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

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2007, 2006 and 2005
(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity
Balances at January 1, 2005	$ 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	-	(1,120)	-	-	(1,117)
Tax impact of stock option exercises	-	-	2,480	-	-	2,480
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	-	9,256	-	-	9,261
Tax impact of stock option exercises	-	-	3,444	-	-	3,444
Deferred director fees - stock compensation	-	-	335	-	-	335
Cash dividends declared - $.30 per share, including RSU dividend equivalents	-	-	-	(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
Stock-based compensation (484,451 shares)	4	-	12,930	-	-	12,934
Tax impact of stock option exercises	-	-	3,049	-	-	3,049
Deferred director fees - stock compensation	-	-	445	-	-	445
Cash dividends declared - $.30 per share, including RSU dividend equivalents	-	-	-	(13,292)	-	(13,292)
Cumulative effect of accounting change from adoption of FIN 48	-	-	-	(63)	-	(63)
Unrealized loss on derivatives	-	-	-	-	(100,727)	(100,727)
Net income	-	-	-	129,928	-	129,928
Balances at December 31, 2007	$ 425	$ 18	$ 66,590	$ 513,645	$ (120,704)	$ 459,974

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

BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2007, 2006 and 2005
(In Thousands)

Cash flows from operating activities:	2007	2006	2005
Net income	$ 129,928	$ 107,943	$ 112,356
Depreciation, depletion and amortization	97,259	71,011	41,410
Dry hole and impairment	12,951	8,253	5,705
Commodity derivatives	574	(109)	-
Stock-based compensation expense	8,200	6,436	1,703
Deferred income taxes	62,465	51,666	20,847
Gain on sale of asset	(54,173)	(97)	(130)
Other, net	3,561	544	408
Cash paid for abandonment	(1,188)	606	(1,381)
Increase in current assets other than cash, cash equivalents and short-term investments	(47,876)	(16,338)	(26,717)
Increase in current liabilities other than line of credit	36,578	13,314	33,579
Net cash provided by operating activities	248,279	243,229	187,780
Cash flows from investing activities:			
Exploration and development of oil and gas properties	(281,702)	(265,110)	(118,718)
Property acquisitions	(56,247)	(257,840)	(112,249)
Additions to vehicles, drilling rigs and other fixed assets	(3,565)	(21,306)	(11,762)
Capitalized interest	(18,104)	(9,339)	-
Proceeds from sale of assets	72,405	4,812	130
Net cash used in investing activities	(287,213)	(548,783)	(242,599)
Cash flows from financing activities:			
Proceeds from issuances on line of credit	395,150	327,250	18,000
Payments on line of credit	(396,850)	(322,750)	(6,500)
Proceeds from issuance of long-term debt	229,300	569,700	144,000
Payments on long-term debt	(174,300)	(254,700)	(97,000)
Dividends paid	(13,292)	(13,177)	(13,228)
Book overdraft	(9,400)	15,246	1,921
Repurchase of shares	-	(18,713)	(6,314)
Proceeds from stock option exercises	5,178	3,156	-
Excess tax benefit	3,049	3,444	-
Debt issuance costs	(1)	(5,476)	(760)
Net cash provided by financing activities	38,834	303,980	40,119
Net decrease in cash and cash equivalents	(100)	(1,574)	(14,700)
Cash and cash equivalents at beginning of year	416	1,990	16,690
Cash and cash equivalents at end of year	$ 316	$ 416	$ 1,990
Supplemental disclosures of cash flow information:			
Interest paid	$ 33,945	$ 15,019	$ 5,275
Income taxes paid	$ 6,715	$ 18,148	$ 26,544
Supplemental non-cash activity:			
Increase (decrease) in fair value of derivatives:			
Current (net of income taxes of ($36,562), $4,188, and ($3,631), respectively)	$ (54,844)	$ 6,282	$ (5,446)
Non-current (net of income taxes of ($30,589), ($1,252), and ($11,965), respectively)	(45,883)	(1,879)	(17,947)
Net increase (decrease) to accumulated other comprehensive income	$ (100,727)	$ 4,403	$ (23,393)
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 invested in cogeneration facilities which provide steam required for the extraction of heavy oil and which generates electricity for sale.

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

Cash and cash equivalents - 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, 2007 and 2006 is $7.8 million and $17.2 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

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

Accounts receivable - 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, 2007 and 2006, we do not have an allowance for doubtful accounts.

Income taxes - We compute income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes* as interpreted by FIN 48, *Accounting for Uncertainty in 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. A valuation allowance is recognized if it is determined that deferred tax assets may not be fully utilized in future periods. FIN 48 also requires that amounts recognized in the Balance Sheet related to uncertain tax positions be classified as a current or noncurrent liability, based upon the expected timing of the payment to a taxing authority.

Derivatives - 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. Settlements are recognized on the Statements of Income under the caption "Sales of oil and gas". 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 Statements of Income 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, will be 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 activities. See Note 15 - Hedging.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

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

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 an asset 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. 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 $1.4 million and $8.9 million as of December 31, 2007 and 2006, respectively, in accordance with SFAS No. 144.

Leases - 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 2005 and 2006 and 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. We routinely enter into noncancelable lease agreements for premises and equipment used in the normal course of business. In addition to minimum rental payments, certain of these leases require additional payments to reimburse the lessors for operating expenses such as real estate taxes, maintenance, utilities and insurance. Rental expense is recorded on a straight-line basis.

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 will be 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 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 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 (ARO) - 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 the 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. The electricity and natural gas we produce and use 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, 2007, 2006 and 2005 was $5.0 million, $5.3 million and $5.7 million, respectively.

Shipping and handling costs - Shipping and handling costs, consisting 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 $6.7 million, $6.8 million and $5.8 million for 2007, 2006 and 2005, respectively. Additionally, the transportation costs in the Uinta basin were $1.4 million and $1.1 million in 2007 and 2006, respectively.

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 implementation of FAS123(R) did not have a material impact on us. 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. We recognize stock option compensation expense from the date of grant to the vesting date.

In accounting for the income tax benefits associated with employee exercises of share-based payments, we have elected to adopt the alternative simplified method as permitted by FASB Staff Position (“FSP”) No. FAS 123(R)-3, *Accounting for the Tax Effects of Share-Based Payment Awards*. FSP No. FAS 123(R)-3 permits the adoption of either the transition guidance described in SFAS No. 123(R) or the alternative simplified method specified in FSP No. FAS 123(R)-3 to account for the income tax effects of share-based payment awards. In determining when additional tax benefits associated with share-based payment exercises are recognized, we follow the ordering of deductions under the tax law, which allows deductions for share-based payment exercises to be utilized before previously existing net operating loss carryforwards. In computing dilutive shares under the treasury stock method, we do not reduce the tax benefit within the calculation for the amount of deferred tax assets.

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. Nonqualified stock options totaling 855,000, 499,000, and 23,000 were excluded from the calculation of diluted net income per common share for 2007, 2006 and 2005, respectively, because they were antidilutive. The assumed proceeds in the treasury stock calculation include proceeds received for the grant price and the tax windfall/shortfall amounts recognized in the financial statements.

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.

Subsidiaries - We have two subsidiaries which serve to gather and transport natural gas in our Lake Canyon and Brundage Canyon fields. These subsidiaries are accounted for using the equity method and our net investment in these entities is included under the caption “Other assets” on our Balance Sheet.

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 added into the depreciable base of our assets and is expensed on a units of production basis over the life of the respective project.

Recent accounting developments - 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 principles, 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 June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. 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. We adopted this interpretation in the first quarter of 2007. See Note 9.

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 effect this statement may have on our financial statements. However, we do not believe that the implementation of SFAS 157 will have a material impact 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* was issued by the Securities and Exchange Commission. 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 our results of 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 do not expect the Statement to have a material effect on our financial statements.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

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

In April 2007, the FASB issued a FASB Staff Position to amend FASB Interpretation 39, *Offsetting of Amounts Related to Certain Contracts*. FIN 39-1 states that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with paragraph 10 of Interpretation 39. FIN 39-1 will become effective for our fiscal year beginning January 1, 2008, and will have no effect on our financial statements, as we do not post collateral under our hedging agreements.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements*. SFAS 160 was issued to establish accounting and reporting standards for the noncontrolling interest in a subsidiary (formerly called minority interests) and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. We do not expect the adoption of SFAS 160 to have a material effect on our financial statements and related disclosures. The effective date of this Statement is the same as that of the related Statement 141(R).

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*, which improves the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply it before that date. We may experience a financial statement impact depending on the nature and extent of any new business combinations entered into after the effective date of SFAS No. 141(R).

3. Fair Value of Financial Instruments

Cash equivalents consist principally of commercial paper investments. Cash and equivalents of $.3 million and $.4 million at December 31, 2007 and 2006, respectively, are stated at cost, which approximates market.

Our short-term investments available for sale at December 31, 2007 and 2006 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, 2007, realized and unrealized gains and losses of our short-term investments were insignificant to the financial statements. The fair value of our long-term senior subordinated notes is approximately $204.5 million and the carrying value of the remainder of our long-term debt approximates 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.

On November 21, 2005, we entered into a new crude oil sales contract with an independent refiner for substantially all of our California production for deliveries beginning February 1, 2006.

On February 27, 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin crude oil. Under the agreement, the refiner began purchasing 3,200 gross Bbl/D beginning July 1, 2007. Upon completion of its refinery expansion in Salt Lake City, which is expected in the first half of 2008, the refiner will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, including transportation, is at a fixed percentage of WTI, which was near the posted price at the contract's starting date.

For the three years ended December 31, 2007, we have experienced no credit losses on the sale of oil, natural gas, natural gas liquids or on hedging contracts. 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, 2007, we have not incurred losses related to these investments. While a significant portion of our hedges are with one counterparty, we utilize multiple counterparties and monitor each counterparty's credit rating.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

4. Concentration of Credit Risks (Cont'd)

The following summarizes the accounts receivable balances at December 31, 2007 and 2006 and sales activity with significant customers for each of the years ended December 31, 2007, 2006 and 2005 (in thousands). We do not believe that the loss of any one customer would impact the marketability, but may impact the profitability of our 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 could impact the marketability of a portion of our Utah crude oil volumes.

	Accounts Receivable As of December 31,		Sales before hedging and royalties For the Year Ended December 31,		
Customer	2007	2006	2007	2006	2005
Oil & Gas Sales:					
A	$ 5,347	$ -	$ 39,791	$ -	$ -
B	-	2,732	20,239	75,597	81,342
C	5,793	2,980	28,170	10,458	-
D	44,450	28,768	404,038	305,587	-
E	-	-	18,000	21,317	-
	$ 55,590	$ 34,480	$ 510,238	$ 412,959	$ 81,342
Electricity Sales:					
F	$ 1,979	$ 4,279	$ 26,033	$ 24,335	$ 24,391
G	2,573	5,658	29,470	28,597	30,893
	$ 4,552	$ 9,937	$ 55,503	$ 52,932	$ 55,284

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.

5. Oil and Gas Properties, Buildings and Equipment

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

	2007	2006
Oil and gas:		
Proved properties:		
Producing properties, including intangible drilling costs	$ 869,176	$ 649,928
Lease and well equipment (1)	448,100	358,392
	1,317,276	1,008,320
Unproved properties		
Properties, including intangible drilling costs	285,823	309,959
Lease and well equipment	-	25
	285,823	309,984
	1,603,099	1,318,304
Less accumulated depreciation, depletion and amortization	350,604	258,466
	1,252,495	1,059,838
Commercial and other:		
Land	810	774
Drilling rigs and equipment	12,443	10,478
Buildings and improvements	5,407	5,596
Machinery and equipment	18,525	16,025
	37,185	32,873
Less accumulated depreciation	14,589	12,080
	22,596	20,793
	$ 1,275,091	$ 1,080,631

(1) *Includes cogeneration facility costs.*

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

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

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.

In July 2006, we paid $51 million, the first installment of the total $153 million, and thereby earned the assignment of the 4,300 gross acres. In November 2006, we paid the second installment of approximately $48 million. We paid the third and final installment of approximately $54 million in May 2007. Prior to February 2011, 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. As of the date of the agreement there were no operating activities from these gas assets.

In January 2005, we acquired certain interests in the Niobrara field of the DJ basin in northeastern Colorado for approximately $105 million 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 have been prepared to report the effect on our results of operations under the purchase method of accounting as if it had been consummated on January 1, 2005. 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 shows the results (in thousands, except per share data):

	2005
Proforma Revenue	$ 408,088
Proforma Income from operations	190,970
Proforma Net income	112,660
Proforma Basic earnings per share	5.11
Proforma Diluted earnings per share	5.01

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):

	2007	2006	2005
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 6,826	$ 89	$ 6,037
Capitalized exploratory well costs that have been capitalized for a period greater than one year	-	-	-
Balance at December 31	$ 6,826	$ 89	$ 6,037
Number of projects that have exploratory well costs that have been capitalized for a period of greater than one year	-	-	-

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

	2007	2006	2005
Beginning balance at January 1	$ 89	$ 6,037	$ 3,452
Additions to capitalized exploratory well costs pending the determination of proved reserves	6,826	6,682	8,840
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	-	(4,377)	(3,369)
Capitalized exploratory well costs charged to expense	(89)	(8,253)	(2,886)
Ending balance at December 31	$ 6,826	$ 89	$ 6,037

Dry hole, abandonment and impairment and asset sales

In 2007 we had dry hole, abandonment, impairment and exploration charges of $13.7 million that consisted primarily of a $4.6 million writedown a portion of our Tri-State acreage in connection with the current and pending sale of these properties, a $3.3 million impairment of our Coyote Flats prospect to reflect its fair value in conjunction with the preparation of our year end reserve estimates, a $2.9 million writedown of our Bakken properties which were sold in September 2007, geological and geophysical costs of $.7 million and other dry hole charges of $2.2 million.

In 2006, there was $8.3 million of dry hole, abandonment and impairment charges that consisted 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 the DJ basin for $1.5 million. For the year ended 2005, costs of $5.7 million were incurred on the following: one exploratory well on the Coyote Flats prospect, one well on the Midway-Sunset property, two exploratory wells at northern Brundage Canyon in the Uinta basin, and an impairment charge of $2.5 million on the remaining carrying value of our Illinois and eastern Kansas prospective CBM acreage were charged to expense.

In May 2007, we sold our non-core West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million and we recognized a $52 million pretax gain on the sale, including post closing adjustments. We completed the sale of a portion of our Tri-State acreage during the fourth quarter of 2007 and have classified $1.4 million as held for sale at December 31, 2007 which reflects additional acreage that we plan to sell in the first quarter of 2008 in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

6. Long-term and Short-term Debt Obligations

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, 2007 the outstanding balance under this Line of Credit was $14.3 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, 2007 and 2006 was 5.7% and 7.3%, respectively.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

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

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 2006 installment under the joint venture agreement to develop properties in the Piceance basin.

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. In 2007, we increased our borrowing base from $500 to $550 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 $259 million at December 31, 2007, leaving $291 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), which is estimated to be over $1 billion as of December 31, 2007. Additionally, as long as the interest coverage ratio (as defined) is met, we may incur additional debt. We were in compliance with all such covenants as of December 31, 2007. The weighted average interest rate on total long-term outstanding borrowings at December 31, 2007 and 2006 was 6.9% and 6.2%, respectively.

Additionally, in June 2006 and July 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

In March 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 in June 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, 2007, we repurchased 818,000 shares in the open market for approximately $25 million. Our repurchase plan expired and no shares were repurchased in 2007.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

7. Shareholders' Equity (Cont'd)

Dividends

Our regular annual dividend is currently $.30 per share, payable quarterly in March, June, September and December. 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.

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 if we have exhausted our restricted payments basket, 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 2007, 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.

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

	2007	2006
Beginning balance at January 1	$ 26,135	$ 10,675
Liabilities incurred	4,191	5,711
Liabilities settled	(2,121)	(862)
Revisions in estimated liabilities	5,779	9,176
Accretion expense	2,442	1,435
Ending balance at December 31	$ 36,426	$ 26,135

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

9. Income Taxes

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

	2007	2006	2005
Current:			
Federal	$ 12,939	$ 12,231	$ 22,666
State	5,299	4,547	6,990
	18,238	16,778	29,656
Deferred:			
Federal	53,321	44,205	20,640
State	9,144	7,461	207
	62,465	51,666	20,847
Total	$ 80,703	$ 68,444	$ 50,503

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

	2007	2006
Deferred tax asset:		
Federal benefit of state taxes	$ 8,391	$ 4,248
Credit carryforwards	33,588	33,338
Stock option costs	6,716	3,989
Derivatives	80,469	13,275
Other, net	3,010	3,450
	132,174	58,300
Deferred tax liability:		
Depreciation and depletion	(232,451)	(162,560)
Net deferred tax liability	$ (100,277)	$ (104,260)

At December 31, 2007, our net deferred tax assets and liabilities were recorded as a current asset of $28.5 million and a long-term liability of $128.8 million. 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.

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

	2007	2006	2005
Tax computed at statutory federal rate	35 %	35%	35%
State income taxes, net of federal benefit	5	5	3
Tax credits	-	-	(7)
Other	(2)	(1)	-
Effective tax rate	38 %	39%	31%

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 purposes, respectively.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

9. Income Taxes (Cont'd)

In June 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. The Interpretation addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

We adopted the provisions of FIN No. 48 on January 1, 2007 and recognized no material adjustment to retained earnings. As of December 31, 2007, we had a gross liability for uncertain tax benefits of $12 million of which $9.1 million, if recognized, would affect the effective tax rate. We recognize potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. As of December 31, 2007, we had accrued approximately $1.1 million of interest related to our uncertain tax positions. The current portion of income taxes payable decreased from a prepaid amount of $3.6 million at year end 2006 to a $2.6 million liability at December 31, 2007. Approximately $1.6 million related to the reclassification of tax uncertain tax positions for which a cash tax payment is not expected to be made in the next twelve months to other noncurrent liabilities in accordance with FIN No. 48.

Due to the uncertainty about the periods in which examinations will be completed and limited information related to current audits, we are not able to make reasonably reliable estimates of the periods in which cash settlements will occur with taxing authorities for the noncurrent liabilities.

For the year ended December 31, 2007 we recognized a net benefit of approximately $.6 million to the Statements of Income due to the closure of certain federal and state tax years, offset by additional FIN 48 accruals net of interest expense of approximately $.2 million.

The following table illustrates changes in our gross unrecognized tax benefits (in millions):

		2007
Unrecognized tax benefits at January 1, 2007	$	14.6
Increases for positions taken in current year		.5
Decreases for positions taken in a prior year		(.3)
Decreases for settlements with taxing authorities		-
Decreases for lapses in the applicable statute of limitations		(2.8)
Unrecognized tax benefits at December 31, 2007	$	12.0

As of December 31, 2007, we remain subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction:	Tax Years Subject to Exam:
Federal	2004 – 2006
California	2003 – 2006
Colorado	2003 – 2006
Utah	2004 – 2006

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

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 2005 and 2006, respectively. The total net investment in these rigs is approximately $8.8 million at December 31, 2007. 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, 2007 are as follows (in thousands):

Net minimum lease payments receivable	$	10,236
Unearned income		(1,437)
Net investment in direct financing lease	$	8,799

As of December 31, 2007, estimated future minimum lease payments, including the purchase option, to be received are as follows (in thousands):

2008	$	4,545
2009		5,752
Total	$	10,297

11. Commitments and Contingencies

We have no accrued environmental liabilities for our sites, including sites in which governmental agencies have designated us as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot 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 incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in substantial costs incurred. 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 our operations or liquidity.

During the California energy crisis in 2000 and 2001, we had electricity sales contracts with various utilities and a portion of the electricity prices paid to us under such contracts from December, 2000 to March 27, 2001 has been under a degree of legal challenge since that time. It is possible that we may have a liability pending the final outcome of the CPUC proceeding on the matter. We believe that any resolution of such dispute should be immaterial to us.

Our contractual obligations not included in our Balance Sheet as of December 31, 2007 are as follows (in thousands):

	Total	2008	2009	2010	2011	2012	Thereafter
Operating lease obligations	12,407	1,690	1,374	1,357	1,357	1,357	5,272
Drilling and rig obligations	74,749	23,559	18,817	7,353	25,020	-	-
Firm natural gas transportation contracts	173,243	15,206	19,545	19,544	19,545	19,054	80,349
Total	$ 260,399	$ 40,455	$ 39,736	$ 28,254	$ 45,922	$ 20,411	$ 85,621

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, 2007, 2006 and 2005 was $1.5 million, $1 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 obligations - Starting in 2006, we began to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the four year contract. Our minimum obligation under our exploration and development agreement is $9.6 million, and as of December 31, 2007 the remaining obligation is $5.4 million. Also included above, under our June 2006 joint venture agreement in the Piceance basin, we are required to have 120 wells drilled by February 2011 to avoid penalties of $.2 million per well or a maximum of $24 million. As of December 31, 2007 we have drilled 12 of these wells.

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

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

11. Commitments and Contingencies (Cont'd)

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 have seven long-term transportation contracts on four different pipelines to provide us with physical access to move gas from our producing areas to various markets.

Other obligations. On February 27, 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D on July 1, 2007. Upon completion of its refinery expansion in Salt Lake City, which is expected in the first half of 2008, the refiner will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI, which was near the posted price at the contract's starting date.

12. Equity Compensation Plans

In December 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 in December 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 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. The grants made to the non-employee Directors vest immediately. We generally use a broker for issuing new shares upon option exercise.

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 in the Statements of Income was $8.4 million, $6.1 million and $2.9 million in 2007, 2006 and 2005, respectively. The tax benefit related to this compensation cost was $3.3 million, $2.4 million and $1.2 million in 2007, 2006 and 2005, respectively.

Stock Options

During 2007, each of the non-employee Directors received 3,956 options at the market value on the date of grant. 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 recipients 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 recipients 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.

	2007	2006	2005
Expected volatility	32% - 33%	32% - 33%	28% - 32%
Weighted-average volatility	33%	32%	32%
Expected dividends	1%	.8% - 1.0%	.92% - 1.3%
Expected term (in years)	4.9 - 5.6	5.3 - 5.5	4 - 5
Risk-free rate	3.4% - 4.7%	4.5% - 4.8%	3.8% - 4.4%

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

12. Equity Compensation Plans (Cont'd)

The following table summarizes information related to stock options outstanding and exercisable as of December 31, 2007:

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
$6.00 - $15.50	728,900	$ 10.29	5.3	678,900	$ 9.98	5.21
$15.51 - $25.00	571,450	21.60	6.9	402,950	21.61	6.91
$25.01 - $34.50	999,801	31.81	8.5	431,326	31.46	8.40
$34.51 - $44.00	227,115	43.36	9.9	45,604	42.38	9.55
Total	2,527,266	$ 24.33	7.3	1,558,780	$ 19.88	6.66

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

	2007	2006	2005
Outstanding at January 1	$ 20.97	$ 16.76	$ 12.70
Granted during the year	43.40	32.82	29.56
Exercised during the year	12.52	10.83	8.40
Cancelled/expired during the year	22.88	19.11	18.68
Outstanding at December 31	24.33	20.97	16.76
Exercisable at December 31	19.88	16.24	12.31

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

	2007	2006	2005
Balance outstanding, January 1	2,859,836	3,110,826	3,131,250
Granted	220,115	604,050	598,926
Exercised	(444,216)	(526,990)	(605,200)
Canceled/expired	(108,469)	(328,050)	(14,150)
Balance outstanding, December 31	2,527,266	2,859,836	3,110,826
Balance exercisable at December 31	1,558,780	1,493,067	1,423,076
Available for future grant	988,798	1,279,344	2,159,174
Weighted average remaining contractual life (years)	7.3	8	8
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$ 13.88	$ 11.27	$ 9.58

As of December 31, 2007, there was $8.1 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 of 1.6 years. The tax benefit realized from stock options exercised during the year ended December 31, 2007, 2006 and 2005 is $3.5 million, $4.3 million and zero, respectively.

	Stock Options		
		Year ended	
	December 31, 2007	December 31, 2006	December 31, 2005
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$ 13.88	$ 11.27	$ 9.58
Total intrinsic value of options exercised (in millions)	11.9	11.8	12.6
Total intrinsic value of options outstanding (in millions)	50.8	29.8	36.8
Total intrinsic value of options exercisable (in millions)	38.3	22.3	26.2

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 and non-employee Directors. 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. During 2007, each of the non-employee Directors received 1,319 RSUs. The RSUs granted to the non-employee Directors are 100% vested at date of grant but are subject to a deferral election before the corresponding shares are issued of a minimum of four years or until they leave the Board of Directors or upon change of control. 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, 2007:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	459,155	$ 31.59	3.3 years
Granted	159,779	42.36	
Converted	(64,633)	31.80	
Canceled/expired	(47,378)	32.93	
Balance outstanding, December 31	506,923	$ 34.84	2.7 years

	RSUs Year ended December 31, 2007	December 31, 2006	December 31, 2005
Weighted-average grant date fair value of RSUs issued	$ 42.36	$ 31.86	$ 30.65
Total value of RSUs vested (in millions)	2.1	1.0	-
Total value of RSUs outstanding (in millions)	17.6	14.2	4.1

The total compensation cost related to nonvested awards not yet recognized on December 31, 2007 is $12.7 million and the weighted average period over which this cost is expected to be recognized is 1.6 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 $1.4 million, $1.2 million and $1.1 million for 2007, 2006 and 2005, respectively. Employees are eligible to participate in the 401(k) Plan on their date of hire and approximately 96% of our employees participated in the 401(k) Plan in 2007.

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. Shares earned and deferred in accordance with the plan as of December 31, 2007, 2006 and 2005 were 12,866, 13,387 and 13,770, respectively.

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.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

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.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. While a significant portion of our hedges are with one counterparty, we utilize multiple counterparties and monitor each counterparty's credit rating. We are not required to issue collateral on these hedging transactions.

We entered into derivative contracts (natural gas swaps and collar contracts) in March 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 2006 at their fair value on the Balance Sheet and we recognized an unrealized net loss of approximately $4.8 million on the Statements of Income 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 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, in June 2006 and July 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, 2007, our net fair value of derivatives liability was $201.6 million as compared to $33.2 million at December 31, 2006. Based on NYMEX strip pricing as of December 31, 2007, we expect to make hedge payments under the existing derivatives of $94.3 million during the next twelve months. At December 31, 2007 and 2006, Accumulated Other Comprehensive Loss consisted of $120.7 million and $20 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, 2007. Deferred net losses recorded in Accumulated Other Comprehensive Loss at December 31, 2007 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts.

16. Master Limited Partnership

On October 22, 2007, we announced plans to form a master limited partnership (MLP) with an initial public offering of common units representing limited partner interests in the MLP. Our previously announced plans to proceed with a master limited partnership for certain of our assets is currently on hold due to the unfavorable capital market conditions.

17. Related Party Transaction

In December 2007, we accepted a tender issued by Bakersfield Fuel & Oil Company (BFO) to purchase all of our shares in BFO for $2.9 million. These proceeds are reflected in the "Proceeds from sale of assets" line on the Statements of Cash Flows and in the "Gain on sale of assets" line in the Statements of Income. Mr. Thomas Jamieson is a Director of Berry Petroleum Company and a director and the controlling stockholder of BFO. The tender was made to all shareholders of BFO other than Mr. Jamieson and his affiliates. The Corporate Governance and Nominating Committee, with input from the Audit Committee, approved this transaction.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

18. Quarterly Financial Data (unaudited)

The following is a tabulation of unaudited quarterly operating results for 2007 and 2006 (in thousands, except per share data).

2007	Operating Revenues	Income Before Taxes	Net Income	Basic Net Income Per Share	Diluted Net Income Per Share
First Quarter	$ 116,369	$ 31,149	$ 18,855	$ .43	$ .42
Second Quarter	127,293	85,778	51,957	1.18	1.16
Third Quarter	130,974	42,273	26,855	.61	.60
Fourth Quarter	148,383	51,431	32,261	.73	.71
	$ 523,019	$ 210,631	$ 129,928	$ 2.95	$ 2.89
2006					
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

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)	2007	2006	2005
Proved properties	$ -	$ 33,390	$ 97,348
Unproved properties	56,247	224,450	24,566
Development (2)	278,398	277,613	112,255
Exploration (3)	23,325	22,435	11,310
	$ 357,970	$ 557,888	$ 245,479

(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 $1.2 million, $.5 million and $.6 million charged to expense during 2007, 2006 and 2005, respectively.*
(3) *Exploration costs include $5.2 million, $3.8 million and $3.6 million that were charged to expense during 2007, 2006 and 2005, respectively. Exploration costs include $18.1 million and $9.3 million of capitalized interest in 2007 and 2006, respectively.*

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

	2007	2006	2005
Sales to unaffiliated parties	$ 467,400	$ 430,497	$ 349,691
Production costs	(158,433)	(132,298)	(110,572)
Depreciation, depletion and amortization	(93,691)	(67,668)	(38,150)
Dry hole, abandonment, impairment and exploration	(13,657)	(12,009)	(9,354)
	201,619	218,522	191,615
Income tax expense	(77,250)	(85,970)	(57,872)
Results of operations from producing and exploration activities	$ 124,369	$ 132,552	$ 133,743

BERRY PETROLEUM COMPANY
Supplemental Information About Oil & Gas Producing Activities (Unaudited) (Cont'd)

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.

The following disclosures of oil and gas reserves are based on estimates prepared by independent engineering consultants as of December 31, 2007, 2006 and 2005. 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.

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, 2007, 2006 and 2005, and changes in such quantities during each of the years then ended were as follows (in thousands):

	2007			2006			2005		
	Oil Mbbl	Gas MMcf	MBOE	Oil Mbbl	Gas MMcf	MBOE	Oil Mbbl	Gas MMcf	MBOE
Proved developed and Undeveloped reserves:									
Beginning of year	112,538	226,363	150,262	103,733	135,311	126,285	105,549	25,724	109,836
Revision of previous estimates	(3,826)	3,358	(3,262)	(512)	(222)	(553)	(681)	4,084	-
Improved recovery	4,500	-	4,500	11,900	-	11,900	753	-	753
Extensions and discoveries	17,300	101,400	34,200	4,100	78,000	17,100	6,228	24,605	10,329
Property sales	(6,700)	-	(6,700)	-	-	-	(1,035)	-	(1,035)
Production	(7,210)	(15,657)	(9,819)	(7,183)	(12,526)	(9,270)	(7,081)	(7,919)	(8,401)
Purchase of reserves in place	-	-	-	500	25,800	4,800	-	88,817	14,803
End of year	116,602	315,464	169,179	112,538	226,363	150,262	103,733	135,311	126,285
Proved developed reserves:									
Beginning of year	84,782	104,934	102,270	78,308	70,519	90,061	78,207	20,048	81,549
End of year	78,339	147,346	102,897	84,782	104,934	102,270	78,308	70,519	90,061

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 those cash flows associated with the ultimate settlement of the asset retirement obligation.

BERRY PETROLEUM COMPANY
Supplemental Information About Oil & Gas Producing Activities (Unaudited) (Cont'd)

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

	2007	2006	2005
Future cash inflows	$ 11,211,151	$ 6,195,547	$ 6,088,170
Future production costs	(3,275,397)	(2,497,785)	(2,297,638)
Future development costs	(812,070)	(511,886)	(333,722)
Future income tax expense	(2,286,296)	(892,669)	(1,115,516)
Future net cash flows	4,837,388	2,293,207	2,341,294
10% annual discount for estimated timing of cash flows	(2,417,882)	(1,110,939)	(1,089,914)
Standardized measure of discounted future net cash flows	$ 2,419,506	$ 1,182,268	$ 1,251,380
Average sales prices at December 31:			
Oil ($/Bbl)	$ 79.19	$ 46.15	$ 48.38
Gas ($/Mcf)	$ 6.27	$ 4.45	$ 7.91
BOE Price	$ 66.27	$ 41.23	$ 48.21

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

	2007	2006	2005
Standardized measure - beginning of year	$ 1,182,268	$ 1,251,380	$ 686,748
Sales of oil and gas produced, net of production costs	(326,174)	(300,619)	(240,039)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	1,451,140	(350,877)	702,867
Revisions of previous quantity estimates	(78,758)	(7,359)	5
Improved recovery	108,655	158,213	12,267
Extensions and discoveries	825,775	227,348	168,291
Change in estimated future development costs	(385,656)	(333,663)	(157,068)
Purchases of reserves in place	-	33,390	103,150
Sales of reserves in place	(98,680)	-	(9,613)
Development costs incurred during the period	281,702	277,075	111,613
Accretion of discount	162,257	125,138	87,650
Income taxes	(687,103)	109,918	(392,886)
Other	(15,920)	(7,676)	178,395
Net increase (decrease)	1,237,238	(69,112)	564,632
Standardized measure - end of year	$ 2,419,506	$ 1,182,268	$ 1,251,380

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of December 31, 2007, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended.

Based on their evaluation as of December 31, 2007, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by us in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Management's Report on Internal Control Over Financial Reporting

Internal control over financial reporting is defined in Rule 13a-15(f) and 15d-15(f) promulgated under the Securities Exchange Act of 1934, as amended, as a process designed by, or under the supervision of, our principal executive and principal financial officers, or persons performing similar functions, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;
- 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 our management and Directors; and
- provide reasonable assurance regarding prevention or the timely detection of unauthorized acquisition, or the use or disposition of our 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. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Additionally, 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.

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control - Integrated Framework,* management concluded that our internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers and Corporate Governance

The information called for by Item 10 is incorporated by reference from information under the captions "Corporate Governance", "Meetings and Committees of our Board" and "Compliance with Section 16(a) of the Securities Exchange Act of 1934" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year. Information regarding Executive Officers is contained in this report in Item 1 Business of this Form 10-K.

Item 11. Executive Compensation

The information called for by Item 11 is incorporated by reference from information under the caption "Executive Compensation" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information called for by Item 12 is incorporated by reference from information under the captions "Security Ownership" and "Principal Shareholders" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year and Item 5 Market for the Registrant's Common Equity and Related Shareholder Matters and Issuer Purchases of Equity Securities of this Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information called for by Item 13 is incorporated by reference from information under the caption "Certain Relationships and Related Transactions" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

Item 14. Principal Accounting Fees and Services

The information called for by Item 14 is incorporated by reference from the information under the caption “Fees to Independent Registered Public Accounting Firms for 2007 and 2006” in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Financial Statements and Schedules

See Item 8 Index to Financial Statements and Supplementary Data in this Form 10-K.

B. Exhibits

Exhibit No.	Description of Exhibit
3.1*	Registrant's Amended and Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Registrant’s Quarterly Report on Form 10-Q for the period ended June 30, 2006, File No. 1-09735).
3.2*	Registrant's Restated Bylaws dated July 1, 2005 (filed as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005, File No. 1-09735).
4.1*	First Supplemental Indenture, dated as of October 24, 2006, between the Registrant and Wells Fargo Bank, National Association as Trustee relating to the Registrant's 8 1/4% Senior Subordinated Notes due 2016 (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K File No. 1-9735).
4.2*	Registrant’s 8.25% Senior Subordinated Notes (filed as Form 425B5 on October 19, 2006).
4.3*	Registrant's Certificate of Designation, Preferences and Rights of Series B Junior Participating Preferred Stock (filed as Exhibit A to the Registrant's Registration Statement on Form 8-A12B on December 7, 1999, File No. 778438-99-000016).
4.4*	Rights Agreement between Registrant and ChaseMellon Shareholder Services, L.L.C. dated as of December 8, 1999 (filed by the Registrant on Form 8-A12B on December 7, 1999, File No. 778438-99-000016).
10.1*	Description of Short-Term Cash Incentive Plan of Registrant (filed as Exhibit 10.1 to the Registrant’s Annual Report on Form 10-K for the period ended December 31, 2006, File No. 1-0735).
10.2*	Form of Change in Control Severance Protection Agreement dated August 24, 2006, by and between Registrant and selected employees of the Company (filed as Exhibit 99.1 to the Registrant’s Current Report on Form 8-K on August 24, 2006, File No. 1-9735).
10.3*	Instrument for Settlement of Claims and Mutual Release by and among Registrant, Victory Oil Company, the Crail Fund and Victory Holding Company effective October 31, 1986 (filed as Exhibit 10.13 to Amendment No. 1 to the Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240).
10.4*	Credit Agreement, dated as of June 27, 2005, by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005, File No. 1-9735).
10.5*	First Amendment to Credit Agreement, dated as of December 15, 2005 by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions (filed as Exhibit 3.1 to the Registrant’s Annual Report on Form 10-K for the period ended December 31, 2005, File No. 1-09735).

10.6*	Second Amendment to Credit Agreement, dated as of April 28, 2006 by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2006, File No. 1-09735).
10.7*	Amended and Restated 1994 Stock Option Plan (filed as Exhibit 4.1 to the Registrant's Registration Statement on Form S-8 filed on August 20, 2002, File No. 333-98379).
10.8*	First Amendment to the Registrant's Amended and Restated 1994 Stock Option Plan dated as of June 23, 2006 (filed as Exhibit 99.3 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.9*	Berry Petroleum Company 2005 Equity Incentive Plan (filed as Exhibit 4.2 to the Registrant's Form S-8 filed on July 29, 2005, File No. 333-127018).
10.10*	Form of the Stock Option Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 4.3 to the Registrant's Form S-8 filed on July 29, 2005, File No. 333-127018).
10.11*	Form of the Stock Appreciation Rights Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 4.4 to the Registrant's Form S-8 filed on July 29, 2005, File No. 333-127018).
10.12*	Form of Restricted Stock Award Agreement, by and between Registrant and selected directors (filed as Exhibit 99.1 on Form 8-K filed on December 17, 2007, File No. 1-9735).
10.13*	Form of Restricted Stock Award Agreement, by and between Registrant and selected officers (filed as Exhibit 99.1on Form 8-K December 17, 2007, File No. 1-9735).
10.14*	Form of Stock Award Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 99.4 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.15* **	Carry and Earning Agreement, dated June 7, 2006, between Registrant and EnCana Oil & Gas (USA), Inc. (filed as Exhibit 99.2 on Form 8-K on June 19, 2006, File No. 1-9735).
10.16*	Crude oil purchase contract, dated November 14, 2005 between Registrant and Big West of California, LLC (filed as Exhibit 99.2 on Form 8-K filed on November 22, 2005, File No. 1-9735).
10.17*	Non-Employee Director Deferred Stock and Compensation Plan (as amended effective January 1, 2006) (filed as Exhibit 10.13 to the Registrant's Annual Report on Form 10-K for the period ended December 31, 2005, File No. 1-09735).
10.18*	Amended and Restated Employment Contract dated as of June 23, 2006 by and between the Registrant and Robert F. Heinemann (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.19*	Stock Award Agreement dated as of June 23, 2006 by and between the Registrant and Robert F. Heinemann (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.20*	Amended and Restated Purchase and Sale Agreement between Registrant and Orion Energy Partners, LP (filed as Exhibit 10.17 to the Registrant's Annual Report on Form 10-K for the period ended December 31, 2005, File No. 1-09735).
10.21*	Underwriting Agreement dated October 18, 2006 by and between Registrant and the several Underwriters listed in Schedule 1 thereto (filed as Exhibit 1.1 to the Registrant's Current Report on Form 8-K on October 19, 2006, File No. 1-9735).
10.22* **	Crude Oil Supply Agreement between the Registrant and Holly Refining and Marketing Company - Woods Cross (filed as Exhibit 10.22 to the Registrant's Annual Report on Form 10-K for the period ended December 31,2006, File No. 1-0735).
10.23* **	Purchase and Sale Agreement between the Registrant and Venoco, Inc. dated March 19, 2007 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2007, File No. 1-9735).
23.1	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
23.2	Consent of DeGolyer and MacNaughton.
31.1	Certification of Chief Executive Officer pursuant to SEC Rule 13(a)-14(a).
31.2	Certification of Chief Financial Officer pursuant to SEC Rule 13(a)-14(a).
32.1	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code.
32.2	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code.
99.1*	Form of Indemnity Agreement of Registrant (filed as Exhibit 99.1 in Registrant's Annual Report on Form 10-K filed on March 31, 2005, File No. 1-9735).
99.2*	Form of "B" Group Trust (filed as Exhibit 28.3 to Amendment No. 1 to Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240).

* Incorporated by reference
** Portions of this exhibit have been omitted pursuant to a request for confidential treatment

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 26, 2008.

BERRY PETROLEUM COMPANY

/s/ Robert F. Heinemann	/s/ Ralph J. Goehring	/s/ Shawn M. Canaday
ROBERT F. HEINEMANN	RALPH J. GOEHRING	SHAWN M. CANADAY
President, Chief Executive Officer and Director	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	Controller (Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the dates indicated.

Name	Office	Date
/s/ Martin H. Young, Jr. Martin H. Young, Jr.	Chairman of the Board, Director	February 26, 2008
/s/ Robert F. Heinemann Robert F. Heinemann	President, Chief Executive Officer and Director	February 26, 2008
/s/ Joseph H. Bryant Joseph H. Bryant	Director	February 26, 2008
/s/ Ralph B. Busch, III Ralph B. Busch, III	Director	February 26, 2008
/s/ William E. Bush, Jr. William E. Bush, Jr.	Director	February 26, 2008
/s/ Stephen L. Cropper Stephen L. Cropper	Director	February 26, 2008
/s/ J. Herbert Gaul, Jr. J. Herbert Gaul, Jr.	Director	February 26, 2008
/s/ Thomas J. Jamieson Thomas J. Jamieson	Director	February 26, 2008
/s/ J. Frank Keller J. Frank Keller	Director	February 26, 2008
/s/ Ronald J. Robinson Ronald J. Robinson	Director	February 26, 2008

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-135055) and Form S-8 (Nos. 333-62799, 333-62871, 333-98379 and 333-127018) of Berry Petroleum Company of our report dated February 26, 2008 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP
Los Angeles, California
February 26, 2008

Exhibit 23.2

DeGolyer and MacNaughton

5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 12, 2008

Berry Petroleum Company
5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309-0640

Gentlemen:

In connection with the Annual Report on Form 10-K for the fiscal year ended December 31, 2007, (the Annual Report) of Berry Petroleum Company (the Company), we hereby consent to (i) the use of and reference to our “Appraisal Report as of December 31, 2007 on Certain Properties owned by Berry Petroleum Company,” “Appraisal Report as of December 31, 2006 on Certain Properties owned by Berry Petroleum Company,” and “Appraisal Report as of December 31, 2005 on Certain Properties owned by Berry Petroleum Company,” (the Reports), under the captions “Business” and “Oil and Gas Properties” in Item 1 of the Annual Report, under the caption “Selected Financial Data” in Item 6 of the Annual Report, and under the caption “Supplemental Information About Oil & Gas Producing Activities (Unaudited)” in Item 8 of the Annual Report; and (ii) the use of and reference to the name DeGolyer and MacNaughton as the independent petroleum engineering firm that prepared the Reports under such items; provided, however, that since the cash-flow calculations in the Annual Report include estimated income taxes not included in the Reports, we are unable to verify the accuracy of the cash-flow values in the Annual Report.

Very truly yours,

/s/ DeGOLYER and MacNAUGHTON

Exhibit 31.1

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, President, Chief Executive Officer, and Director certify that:

1. I have reviewed this report on Form 10-K of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report;

4. The Company’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, 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;

   c) evaluated the effectiveness of the Company’s disclosure controls and procedures and presented in this report our conclusions abut the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company’s internal control over financial reporting that occurred during the Company’s most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company’s internal control over financial reporting.

5. The Company’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company’s auditors and the audit committee of the Company’s board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company’s ability to record, process, summarize and report financial information and have identified for the registrant’s auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company’s internal controls over financial reporting.

\s\ Robert F. Heinemann

Robert F. Heinemann
President, Chief Executive Officer, and Director

February 26, 2008

Exhibit 31.2

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Ralph J. Goehring, Executive Vice President and Chief Financial Officer, certify that:

1. I have reviewed this report on Form 10-K of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, 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;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

\s\ Ralph J. Goehring

Ralph J. Goehring

February 26, 2008 — Executive Vice President and Chief Financial Officer

Exhibit 32.1

Certification of Chief Executive Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In connection with the Annual Report of Berry Petroleum Company (the “Company”) on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

\s\ Robert F. Heinemann

Robert F. Heinemann

February 26, 2008

President, Chief Executive Officer and Director

Exhibit 32.2

Certification of Chief Financial Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In connection with the Annual Report of Berry Petroleum Company (the “Company”) on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Ralph J. Goehring, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

\s\ Ralph J. Goehring

Ralph J. Goehring

February 26, 2008

Executive Vice President and Chief Financial Officer