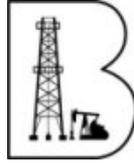


UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549

**FORM 10-K**

x Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934  
For the fiscal year ended **December 31, 2006**  
Commission file number **1-9735**



**BERRY PETROLEUM COMPANY**

(Exact name of registrant as specified in its charter)

**DELAWARE**

**77-0079387**

(State of incorporation or organization)

(I.R.S. Employer Identification Number)

**5201 Truxtun Avenue, Suite 300  
Bakersfield, California 93309**

(Address of principal executive offices, including zip code)

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

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

Title of each class

Name of each exchange on which registered

**Class A Common Stock, \$.01 par value  
(including associated stock purchase rights)**

**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

YES x NO o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

YES o NO x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO x

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

**DOCUMENTS INCORPORATED BY REFERENCE**

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

**BERRY PETROLEUM COMPANY**  
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## PART I

### Item 1. Business

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

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

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

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

### **Business strengths.**

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

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

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

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

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

We continue to engage DeGolyer and MacNaughton (D&M) to appraise the extent and value of our proved oil and gas reserves and the future net revenues to be derived from our properties for the year ended December 31, 2006. D&M is an independent oil and gas consulting firm located in Dallas, Texas. In preparing their reports, D&M reviewed and examined geologic, economic, engineering and other data considered applicable to properly determine our reserves. They also examined the reasonableness of certain economic assumptions regarding forecasted operating and development costs and recovery rates in light of the economic environment on December 31, 2006. See Supplemental Information About Oil & Gas Producing Activities (Unaudited) for our oil and gas reserve disclosures.

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

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

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

#### **Crude Oil and Natural Gas Marketing.**

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

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

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

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

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

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

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

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

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

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

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

**Firm Transportation Summary.**

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

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

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

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

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

**Steaming Operations.**

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

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

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

Total steam generation capacity of Cogeneration plants	38,000
Additional steam purchased under contract with a third party	2,000
Total steam generation capacity of conventional boilers	67,000
Total steam capacity	<u>107,000</u>

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

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

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

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

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

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

Natural gas consumed in:

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

Natural gas produced:

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

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

## **Electricity.**

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

cost of producing heavy oil in California. DD&A related to our cogeneration facilities is allocated between electricity operations and oil and gas operations using a similar allocation method.

**Sales Contracts.** Historically, we have sold electricity produced by our cogeneration facilities, each of which is a Qualifying Facility (QF) under the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA), to two California public utilities; Southern California Edison Company (Edison) and PG&E, under long-term contracts approved by the California Public Utilities Commission (CPUC). These contracts are referred to as standard offer (SO) contracts under which we are paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. An SO2 contract is more beneficial as it requires the utility to pay a higher capacity payment than an SO1 contract. The SRAC energy price is currently determined by a formula approved by the CPUC that reflects the utility's marginal fuel cost and a conversion efficiency that represents a hypothetical resource to generate electricity in the absence of the cogenerator. During most periods natural gas is the marginal fuel for California utilities, so this formula provides a hedge against our cost of gas to produce electricity and steam in our cogeneration facilities. A proceeding is now underway at the CPUC to review and revise the methodology used to determine SRAC energy prices and to determine to what extent the utilities would be required to enter into further contracts with QFs. It is not known when the CPUC will issue a decision on SRAC pricing revisions. Also, there is no assurance that any new methodology will continue to provide a hedge against our fuel cost or that a revised pricing mechanism or terms will be as beneficial as the current contract pricing and terms.

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

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

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

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

**Facility and Contract Summary.**

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

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

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

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

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

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

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

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

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

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

Mbbl - Thousands of barrels

MMcf - Million cubic feet

Bcf - Billion cubic feet

BOE - Barrels of oil equivalent

MBOE - Thousand barrels of oil equivalent

(1) Net production represents that owned by us and produced to our interests.

(2) Equivalent oil and gas information is at a ratio of 6 thousand cubic feet (Mcf) of natural gas to 1 barrel (Bbl) of oil. A barrel of oil is equivalent to 42 U.S. gallons

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

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

(1) Includes 44,583 gross undeveloped acres (22,292 net) where we have an interest in 75% of the deep rights and 25% of the shallow rights.

(2) Does not include 125,000 gross (70,000 net) acres and 125,000 gross (23,000 net) acres at Lake Canyon (shallow) and Lake Canyon (deep), respectively, which we can earn upon fulfilling specific drilling obligations.

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

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

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

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

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

(2) A dry well is a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	2006	
	Gross	Net
<b>Total productive wells drilled:</b>		
Oil	258	254
Gas	281	105

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

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

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

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

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

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

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

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

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

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

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

#### **Forward Looking Statements**

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Form 10-K that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as "will," "might," "intend," "continue," "target(s)," "expect," "achieve," "strategy," "future," "may," "could," "goal(s)," "forecast," "anticipate," or other 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 in Part I, Item 1A on page 15 of this Form 10-K filed with the Securities and Exchange Commission, under the heading "Risk Factors."

## **Item 1A. Risk Factors**

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

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

Among the factors that can cause fluctuations are:

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

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

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

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

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

***Market conditions or operational impediments may hinder our access to crude oil and natural gas markets or delay our production.*** Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and refineries owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of

inadequacy or unavailability of natural gas pipelines, gathering system capacity, processing facilities or refineries. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market. See firm transportation summary schedule at Item 1 Business.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

subject us to administrative, civil and criminal penalties. Furthermore, our business, results from operations and financial condition may be adversely affected by any failure to comply with, or future changes to, these laws and regulations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties and rig availability and access to our drilling locations utilizing available roads. As of December 31, 2006, we own three

drilling rigs, one of which is drilling on our property, and have additional one-year contract commitments on another three drilling rigs. See contractual obligations in Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operation.

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

#### **Item 1B. Unresolved Staff Comments**

None.

#### **Item 2. Properties**

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

#### **Item 3. Legal Proceedings**

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

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

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

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

ROBERT F. HEINEMANN, 53, has been President and Chief Executive Officer since June 2004. Mr. Heinemann was Chairman of the Board and interim President and Chief Executive Officer from April 2004 to June 2004. From December 2003 to March 2004, Mr. Heinemann was the director designated to serve as the presiding director at executive sessions of the Board in the absences of the Chairman and to act as liaison between the independent directors and the CEO. Mr. Heinemann joined the Board in March of 2003. From 2000 until 2002, Mr. Heinemann served as the Senior Vice President and Chief Technology Officer of Halliburton Company and as the Chairman of the Halliburton Technology Advisory Committee. He was previously with Mobil Oil Corporation (Mobil) where he served in a variety of positions for Mobil and its various affiliate companies in the energy and technical fields from 1981 to 1999, with his last responsibilities as Vice President of Mobil Technology Company and General Manager of the Mobil Exploration and Producing Technical Center.

RALPH J. GOEHRING, 50, has been Executive Vice President and Chief Financial Officer since June 2004. Mr. Goehring was Senior Vice President from April 1997 to June 2004, and has been Chief Financial Officer since March 1992 and was Manager of Taxation from September 1987 until March 1992. Mr. Goehring is also an Assistant Secretary.

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

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

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

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

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

SHAWN M. CANADAY, 31, has been Treasurer since December 2004 and was Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and gas industry since 1998 in various finance functions at Chevron and in public accounting. Mr. Canaday is presently an Assistant Secretary. Effective March 2, 2007, Mr. Canaday will replace Mr. Wilson as Controller.

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

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

## PART II

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

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital Stock," are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a \$.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Common Stock at the option of the holder.

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

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

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

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

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

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

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

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

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

#### **Equity Compensation Plan Information.**

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

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

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

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

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

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

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

### Performance Graph

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

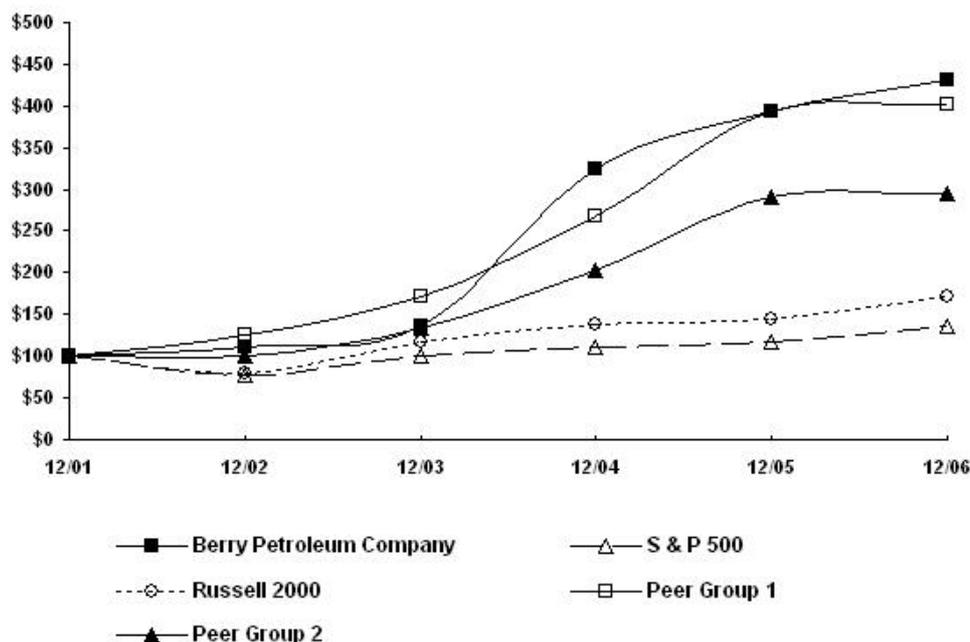
Total returns assume \$100 invested on December 31, 2001 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index (S&P 500) and two Peer Groups, assuming reinvestment of dividends for each measurement period. In the proxy statement filed in 2006, we added Peer Group 1, which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

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

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

## COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN\*

Among Berry Petroleum Company, The S & P 500 Index,  
The Russell 2000 Index And Two Peer Groups



\* \$100 invested on 12/31/01 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

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

### Item 6. Selected Financial Data

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

	2006	2005	2004	2003	2002
<b>Audited Financial Information</b>					
<i>Statement of Income Data:</i>					
Sales of oil and gas	\$ 430,197	\$ 349,691	\$ 226,876	\$ 135,848	\$ 102,026
Sales of electricity	52,932	55,230	47,644	44,200	27,691
Operating costs - oil and gas production	117,624	99,066	73,838	57,830	41,108
Operating costs - electricity generation	48,281	55,086	46,191	42,351	26,747
Production taxes	14,674	11,506	6,431	3,097	2,907
General and administrative expenses (G&A)	36,841	21,396	22,504	14,495	10,417
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	67,668	38,150	29,752	17,258	13,388
Electricity generation	3,343	3,260	3,490	3,256	3,064
Net income	107,943	112,356	69,187	32,363	29,210
Basic net income per share (1)	2.46	2.55	1.58	.74	.67
Diluted net income per share (1)	2.41	2.50	1.54	.73	.67
Weighted average number of shares outstanding (basic) (1)	43,948	44,082	43,788	43,544	43,482
Weighted average number of shares outstanding (diluted) (1)	44,774	44,980	44,940	44,062	43,804
<i>Balance Sheet Data:</i>					
Working capital	\$ (100,594)	\$ (54,757)	\$ (3,840)	\$ (3,540)	\$ (2,892)
Total assets	1,198,997	635,051	412,104	340,377	259,325
Long-term debt	390,000	75,000	28,000	50,000	15,000
Shareholders' equity	427,700	334,210	263,086	197,338	172,774
Cash dividends per share (1)	.30	.30	.26	.24	.20
<i>Operating Data:</i>					
Cash flow from operations	243,229	187,780	124,613	64,825	57,895
Exploration and development of oil and gas properties	265,110	118,718	71,556	41,061	30,163
Property/facility acquisitions	257,840	112,249	2,845	48,579	5,880
Additions to vehicles, drilling rigs and other fixed assets	21,306	11,762	669	494	469
<b>Unaudited Operating Data</b>					
<i>Oil and gas producing operations (per BOE):</i>					
Average sales price before hedging	\$ 48.38	\$ 47.01	\$ 33.64	\$ 24.48	\$ 20.11
Average sales price after hedging	46.67	41.62	30.32	22.52	19.39
Average operating costs - oil and gas production	12.69	11.79	10.09	9.57	7.83
Production taxes	1.58	1.37	.86	.51	.55
G&A	3.98	2.55	2.99	2.40	1.98
DD&A - oil and gas production	7.30	4.54	3.96	2.86	2.55
Production (MBOE)	9,270	8,401	7,517	6,040	5,251
Production (MMWh)	757	741	776	767	748
<i>Proved Reserves Information:</i>					
Total BOE	150,262	126,285	109,836	109,920	101,719
Standardized measure (2)	\$ 1,182,268	\$ 1,251,380	\$ 686,748	\$ 528,220	\$ 449,857
Year-end average BOE price for PV10 purposes	41.23	48.21	29.87	25.89	24.91
<i>Other:</i>					
Return on average shareholders' equity	28.33%	37.63%	31.06%	17.50%	17.90%
Return on average capital employed	18.21%	32.74%	26.29%	15.44%	16.42%

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

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

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

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

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

### **Notable Items in 2006.**

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

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

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

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

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

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

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

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

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

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

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

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

	Gross Wells	Net Wells
SMWSS	50	50
NMWSS	81	80
Socal (1)	38	38
Piceance	68	11
Uinta (2)	108	106
DJ (3)	223	97
<b>Totals</b>	<b>568</b>	<b>382</b>

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

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

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

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

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

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

**California**

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

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

2006 - Development activities were focused on horizontal drilling.

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

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

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

2006 - Completed commercial testing.

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

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

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

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

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

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

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

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

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

### **Rocky Mountain/Mid-Continent**

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

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

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

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

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

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

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

In the Lake Canyon prospect, we hold, with an industry partner, a 169,000 gross acre block which is located immediately west of our Brundage Canyon producing properties. We will drill and operate the shallow wells which target light oil and natural gas in the Green River formation and retain up to a 75% working interest. Our partner will drill and operate deep wells which target hydrocarbons in the Mesaverde and Wasatch formations. We will hold up to a 25% working interest in these deep wells. The Ute Tribe has the option to participate in each well and obtain a 25% working interest which would reduce our and our partner's participation.

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

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

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

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

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

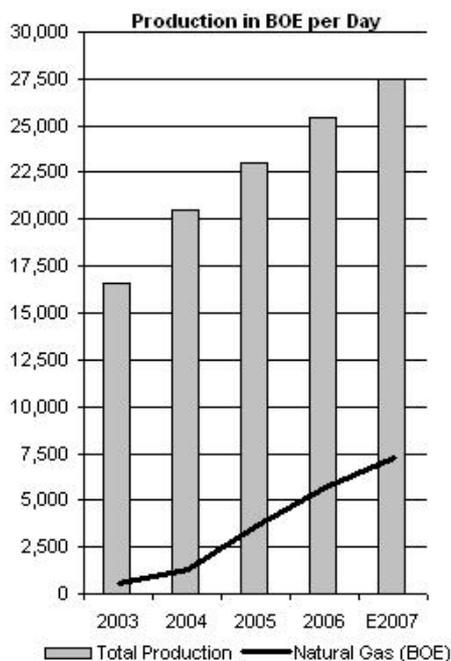
2007 - No capital has been directed at this project, pending results from production tests on the three discovery wells.

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

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

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

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



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

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

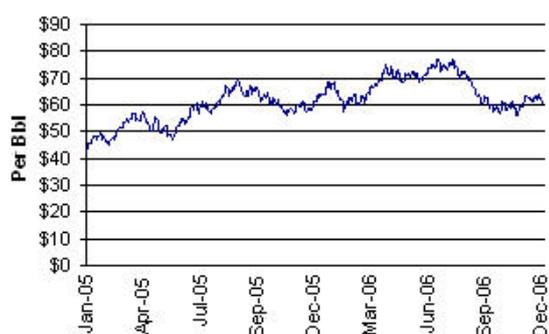
The following companywide results are in millions (except per share data) for the years ended December 31:

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

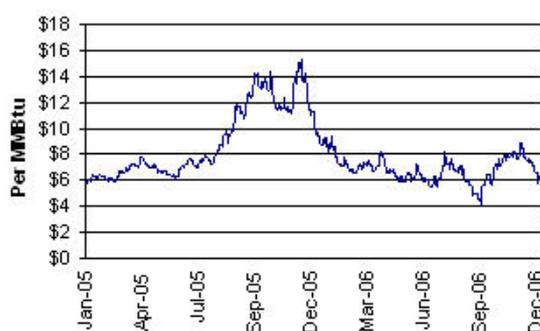
The following companywide results are in millions (except per share data) for the three months ended:

	December 31, 2006	December 31, 2005	September 30, 2006
Sales of oil	\$ 84	\$ 75	\$ 98
Sales of gas	18	23	18
Total sales of oil and gas	\$ 102	\$ 98	\$ 116
Sales of electricity	13	18	12
Interest and other income, net	1	1	1
Total revenues and other income	\$ 116	\$ 117	\$ 129
Net income	\$ 19	\$ 30	\$ 31
Net income per share (diluted)	\$ .43	\$ .69	\$ .70

**WTI NYMEX Crude Oil Price**



**Henry Hub NYMEX Natural Gas Price**



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

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

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

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

The following table is for the three months ended:

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

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

	2006		2005		2004	
<b>Electricity</b>						
Revenues (in millions)	\$	52.9	\$	55.2	\$	47.6
Operating costs (in millions)	\$	48.3	\$	55.1	\$	46.2
Decrease to total oil and gas operating expenses-per barrel	\$	.50	\$	.02	\$	.19
Electric power produced - MWh/D		2,074		2,030		2,121
Electric power sold - MWh/D		1,867		1,834		1,915
Average sales price/MWh (no hedging was in place)	\$	77.13	\$	82.73	\$	70.24
Fuel gas cost/MMBtu (after hedging and excluding transportation)	\$	5.99	\$	7.30	\$	5.46

The following table is for the three months ended:

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

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

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

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

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

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

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

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

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

- **Production taxes:** Our production taxes have increased over the last year as the value of our oil and natural gas has increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the cost of the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. During 2006 our production taxes increased as a result of higher assessed values on our properties, increased production and higher investment in mineral interests. We expect production taxes to track the commodity price generally.
- **Depreciation, depletion and amortization:** DD&A increased per BOE in 2006 due to a large increase in capital spending over the last two years and particularly more extensive development in fields with higher drilling costs. Higher leasehold acquisition costs in 2003 through 2006 are expected to increase our DD&A expense over the life of these assets as development increases. Our capital program is experiencing cost pressures in our labor and for goods and services commensurate with other energy developers. As these costs increase, our DD&A rates per BOE will also increase.
- **General and administrative:** Approximately two-thirds of our G&A is compensation or compensation related costs. Our employee headcount increased 16% as we added an important new core asset into our portfolio and as we are strengthening our talent base. We also re-examined our compensation structure and made necessary changes to attract and retain the talent needed to achieve our growth goals. We are experiencing higher employee turnover rates as the demand for experienced personnel in the energy industry is very high. Other items increasing our G&A in 2006 were contributions to fund the opposition of Proposition 87 in California, increased travel and consulting costs and a generally higher level of activity.
- **Interest expense:** Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, was \$406 million at December 31, 2006 compared to \$87 million at December 31, 2005. Average borrowings in 2006 increased as a result of our Piceance basin acquisitions during 2006 and capital expenditure program. A certain portion of our interest cost related to our Piceance basin acquisition and joint venture has been capitalized into the basis of the assets, and we anticipate a portion will continue to be capitalized during 2006 and 2007 until our probable reserves have been recategorized to proved reserves. For the year ended December 31, 2006, \$9.3 million has been capitalized and we expect to capitalize approximately \$20 million of interest cost during the full year of 2007.

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

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

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

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

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

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

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

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

- Production taxes: Higher prices, such as those exhibited in 2005, create increased production taxes.
- Depreciation, depletion and amortization: DD&A increased per BOE in the year ended 2005 from the year ended 2004 due to higher acquisition costs of our Rocky Mountain/Mid-Continent region assets as compared to our legacy heavy oil assets in California and higher finding and development costs. As these costs increase, our DD&A rates per BOE will also increase.
- General and administrative: Approximately two-thirds of our G&A is compensation or compensation related costs. We intend to remain competitive in workforce compensation to achieve our growth plans. Stock-based compensation expense was \$.35 per BOE and \$.56 per BOE for the years ended December 31, 2005 and 2004, respectively. Compensation expenses increased due to increased staffing resulting from our growth, and increases in compensation levels and bonuses. Additionally, we incurred increased legal and accounting fees, primarily due to compliance with Sarbanes-Oxley, and growth through acquisitions and other financial reporting related matters. Legal and accounting expenses were \$.28 per BOE in 2005 as compared to \$.23 per BOE in 2004.
- Interest expense: We increased our outstanding borrowings to \$75 million at December 31, 2005 as compared to \$28 million at December 31, 2004. Average borrowings increased as a result of acquisitions of \$112 million during 2005. Additionally, interest rates increased by approximately 1.75% since December 31, 2004.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Working Capital and Cash Flows.** Cash flow from operations is dependent upon the price of crude oil and natural gas and our ability to increase production and manage costs. Combined crude oil and natural gas prices increased in 2006 (see graphs on page 33) and we increased production by 10%.

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

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

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

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

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

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

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

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

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

### **Contractual Obligations.**

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

Contractual Obligations	Total	2007	2008	2009	2010	2011	Thereafter
Long-term debt and interest	\$ 609,464	\$ 28,603	\$ 28,603	\$ 28,603	\$ 28,603	\$ 212,552	\$ 282,500
Abandonment obligations	26,135	740	941	991	991	991	21,481
Operating lease obligations	14,208	1,822	1,670	1,375	1,357	1,357	6,627
Property acquisition payable	54,000	54,000	-	-	-	-	-
Drilling and rig obligations	107,333	34,260	28,960	41,989	2,124	-	-
Firm natural gas transportation contracts	73,795	4,801	7,584	8,496	8,659	8,659	35,596
<b>Total</b>	<b>\$ 884,935</b>	<b>\$ 124,226</b>	<b>\$ 67,758</b>	<b>\$ 81,454</b>	<b>\$ 41,734</b>	<b>\$ 223,559</b>	<b>\$ 346,204</b>

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

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

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

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

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

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

A critical accounting policy is one that is important to the portrayal of our financial condition and results, and requires management to make difficult subjective and/or complex judgments. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. We believe the following accounting policies are critical policies.

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

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

**Carrying Value of Long-lived Assets.** Downward revisions in our estimated reserve quantities, increases in future cost estimates or depressed crude oil or natural gas prices could cause us to reduce the carrying amounts of our properties. We perform an impairment analysis of our proved properties annually by comparing the future undiscounted net revenue per the annual reserve valuation prepared by our independent reserve engineers to the net book carrying value of the assets. An analysis of the proved properties will also be performed whenever events or changes in circumstances indicate an asset's carrying value may not be recoverable from future net revenue. Assets are grouped at the field level and if it is determined that the net book carrying value cannot be recovered by the

estimated future undiscounted cash flow, they are written down to fair value. Cash flows used in the impairment analysis are determined based on our estimates of crude oil and natural gas reserves, future crude oil and natural gas prices and costs to extract these reserves. For our unproved properties, we perform an impairment analysis annually or whenever events or changes in circumstances indicate an asset's net book carrying value may not be recoverable.

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

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

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

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

**Accounting for Business Combinations.** We have grown substantially through acquisitions and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations using the purchase method, which is the only method permitted under SFAS 141. The accounting for business combinations is complicated and involves the use of significant judgment. Under the purchase method of accounting, a business combination is accounted for at a purchase price based

upon the fair value of the consideration given, whether in the form of cash, assets, stock or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

second quarter of 2006. The difference of \$.8 million was recorded in other comprehensive income at the date the hedges were designated.

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

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

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

At December 31, 2006, Accumulated Other Comprehensive Loss, net of income taxes, consisted of \$20 million of unrealized losses from our crude oil and natural gas hedges. Deferred net losses recorded in Accumulated Other Comprehensive Loss at December 31, 2006 are expected to be reclassified to earnings over the life of the contracts. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to our hedging activities, we utilize multiple counterparties on our hedges and monitor each counterparty's credit rating.

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

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

	12/31/06 NYMEX Futures	Impact of percent change in futures prices on earnings			
		-20%	-10%	+10%	+20%
Average WTI Futures Price (2007 - 2010)	\$ 66.39	\$ 53.11	\$59.75	\$73.02	\$ 79.66
Crude Oil gain/(loss) (in millions)	-	2.5	.1	(34.8)	(108.2)
Average HH Futures Price (2007 - 2008)	7.51	6.00	6.76	8.26	9.01
Natural Gas gain (in millions)	10.7	26.0	17.1	7.8	3.1
Net pre-tax future cash (payments) and receipts by year (in millions):					
2007 (WTI \$64.35; HH \$6.97)	\$ 4.8	\$ 11.5	\$ 8.0	\$ (3.1)	\$ (26.1)
2008 (WTI \$67.45; HH \$8.06)	5.9	14.5	9.1	(9.6)	(37.2)
2009 (WTI \$67.21)	-	-	-	(14.3)	(38.9)
2010 (WTI \$66.53)	-	2.5	.1	-	(2.9)
Total	\$ 10.7	\$ 28.5	\$ 17.2	\$ (27.0)	\$(105.1)

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

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

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

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed integrated audits of Berry Petroleum Company's financial statements and of its internal control over financial reporting as of December 31, 2006 in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

### Financial statements

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

### Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Los Angeles, California  
February 28, 2007

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

ASSETS	2006	2005
<b>Current assets:</b>		
Cash and cash equivalents	\$ 416	\$ 1,990
Short-term investments	665	661
Accounts receivable	67,905	59,672
Deferred income taxes	-	4,547
Fair value of derivatives	7,349	3,618
Assets held for sale	8,870	-
Prepaid expenses and other	13,604	4,398
<b>Total current assets</b>	<b>98,809</b>	<b>74,886</b>
Oil and gas properties (successful efforts basis), buildings and equipment, net	1,080,631	552,984
Fair value of derivatives	2,356	-
Long-term deferred income taxes	-	1,600
Other assets	17,201	5,581
	<u>\$ 1,198,997</u>	<u>\$ 635,051</u>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
<b>Current liabilities:</b>		
Accounts payable	\$ 69,914	\$ 57,783
Property acquisition payable	54,400	-
Revenue and royalties payable	45,845	34,920
Accrued liabilities	20,415	8,805
Line of credit	16,000	11,500
Income taxes payable	-	1,237
Deferred income taxes	745	-
Fair value of derivatives	8,084	15,398
<b>Total current liabilities</b>	<b>215,403</b>	<b>129,643</b>
<b>Long-term liabilities:</b>		
Deferred income taxes	103,515	55,804
Long-term debt	390,000	75,000
Abandonment obligation	26,135	10,675
Unearned revenue	1,437	866
Fair value of derivatives	34,807	28,853
	<u>555,894</u>	<u>171,198</u>
<b>Commitments and contingencies (Note 11)</b>		
<b>Shareholders' equity:</b>		
Preferred stock, \$.01 par value, 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, \$.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 42,098,551 shares issued and outstanding (21,157,155 on a pre-split basis in 2005)	421	211
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of \$899) (898,892 on a pre-split basis in 2005)	18	9
Capital in excess of par value	50,166	56,064
Accumulated other comprehensive loss	(19,977)	(24,380)
Retained earnings	397,072	302,306
<b>Total shareholders' equity</b>	<b>427,700</b>	<b>334,210</b>
	<u>\$ 1,198,997</u>	<u>\$ 635,051</u>

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

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

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

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

Net income	\$ 107,943	\$ 112,356	\$ 69,187
Unrealized gains (losses) on derivatives, net of income taxes of \$7,647, (\$16,677), and (\$521), respectively	11,471	(25,015)	(781)
Reclassification of realized gains (losses) included in net income net of income taxes of (\$4,712), \$1,081 and \$2,284, respectively	(7,068)	1,622	3,426
Comprehensive income	<u>\$ 112,346</u>	<u>\$ 88,963</u>	<u>\$ 71,832</u>

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

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

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

	Class A	Class B	Capital in Excess of Par Value	Deferred Stock- Based Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity
Balances at January 1, 2004	\$ 209	\$ 9	\$ 56,475	\$ (1,108)	\$ 145,385	\$ (3,632)	\$ 197,338
Adoption of SFAS 123	-	-	(243)	1,108	-	-	865
Stock-based compensation (310,538 shares)	1	-	3,451	-	-	-	3,452
Deferred director fees - stock compensation	-	-	993	-	-	-	993
Cash dividends declared - \$.26 per share	-	-	-	-	(11,394)	-	(11,394)
Unrealized gain on derivatives	-	-	-	-	-	2,645	2,645
Net income	-	-	-	-	69,187	-	69,187
Balances at December 31, 2004	210	9	60,676	-	203,178	(987)	263,086
Shares repurchased and retired (217,800 shares)	(2)	-	(6,314)	-	-	-	(6,316)
Stock-based compensation (294,358 shares)	3	-	1,360	-	-	-	1,363
Deferred director fees - stock compensation	-	-	342	-	-	-	342
Cash dividends declared - \$.30 per share	-	-	-	-	(13,228)	-	(13,228)
Unrealized loss on derivatives	-	-	-	-	-	(23,393)	(23,393)
Net income	-	-	-	-	112,356	-	112,356
Balances at December 31, 2005	211	9	56,064	-	302,306	(24,380)	334,210
Two-for one stock split	211	9	(220)	-	-	-	-
Shares repurchased and retired (600,200 shares)	(6)	-	(18,713)	-	-	-	(18,719)
Stock-based compensation (498,939 shares)	5	-	12,700	-	-	-	12,705
Deferred director fees - stock compensation	-	-	335	-	-	-	335
Cash dividends declared - \$.30 per share	-	-	-	-	(13,177)	-	(13,177)
Unrealized gain on derivatives	-	-	-	-	-	4,403	4,403
Net income	-	-	-	-	107,943	-	107,943
Balances at December 31, 2006	<u>\$ 421</u>	<u>\$ 18</u>	<u>\$ 50,166</u>	<u>\$ -</u>	<u>\$ 397,072</u>	<u>\$ (19,977)</u>	<u>\$ 427,700</u>

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

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

Cash flows from operating activities:	2006	2005	2004
Net income	\$ 107,943	\$ 112,356	\$ 69,187
Depreciation, depletion and amortization	71,011	41,410	33,242
Dry hole	8,253	5,705	745
Abandonment and impairment	606	(1,381)	(1,314)
Commodity derivatives	(109)	-	-
Stock-based compensation expense, net of taxes	6,436	1,703	5,309
Deferred income taxes, net	51,666	20,847	10,815
Other, net	447	278	794
Increase in current assets other than cash, cash equivalents and short-term investments	(16,338)	(26,717)	(11,310)
Increase in current liabilities other than line of credit	13,314	33,579	17,145
<b>Net cash provided by operating activities</b>	<b>243,229</b>	<b>187,780</b>	<b>124,613</b>
<b>Cash flows from investing activities:</b>			
Exploration and development of oil and gas properties	(265,110)	(118,718)	(71,556)
Property acquisitions	(257,840)	(112,249)	(2,845)
Additions to vehicles, drilling rigs and other fixed assets	(21,306)	(11,762)	(669)
Capitalized interest	(9,339)	-	-
Deposits on potential acquisitions	-	-	(10,221)
Proceeds from sale of assets	4,812	130	101
Other, net	-	-	3
<b>Net cash used in investing activities</b>	<b>(548,783)</b>	<b>(242,599)</b>	<b>(85,187)</b>
<b>Cash flows from financing activities:</b>			
Proceeds from issuance of line of credit	327,250	18,000	-
Payment of line of credit	(322,750)	(6,500)	-
Proceeds from issuance of long-term debt	569,700	144,000	-
Payment of long-term debt	(254,700)	(97,000)	(22,000)
Dividends paid	(13,177)	(13,228)	(11,394)
Book overdraft	15,246	1,921	-
Repurchase of shares	(18,713)	(6,315)	-
Proceeds from stock option exercises	3,156	-	-
Excess tax benefit	3,444	-	-
Debt issuance cost	(5,476)	(759)	-
<b>Net cash provided by (used in) financing activities</b>	<b>303,980</b>	<b>40,119</b>	<b>(33,394)</b>
<b>Net (decrease) increase in cash and cash equivalents</b>	<b>(1,574)</b>	<b>(14,700)</b>	<b>6,032</b>
Cash and cash equivalents at beginning of year	1,990	16,690	10,658
<b>Cash and cash equivalents at end of year</b>	<b>\$ 416</b>	<b>\$ 1,990</b>	<b>\$ 16,690</b>
<b>Supplemental disclosures of cash flow information:</b>			
Interest paid	\$ 15,019	\$ 5,275	\$ 1,243
Income taxes paid	\$ 18,148	\$ 26,544	\$ 11,652
<b>Supplemental non-cash activity:</b>			
<b>Increase (decrease) in fair value of derivatives:</b>			
Current (net of income taxes of \$4,188, (\$3,631), and \$1,202, respectively)	\$ 6,282	\$ (5,446)	\$ 1,804
Non-current (net of income taxes of (\$1,252), (\$11,965), and \$561, respectively)	(1,879)	(17,947)	841
<b>Net increase (decrease) to accumulated other comprehensive income</b>	<b>\$ 4,403</b>	<b>\$ (23,393)</b>	<b>\$ 2,645</b>
<b>Non-cash financing activity: Property acquired for debt</b>	<b>\$ 54,000</b>	<b>\$ -</b>	<b>\$ -</b>

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

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

**1. General**

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

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

**2. Summary of Significant Accounting Policies**

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, 2006 is \$17.2 million 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 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, 2006 and 2005, we do not have an allowance for doubtful accounts.

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

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. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivative contracts that do not qualify for hedge accounting under SFAS No. 133 the contracts are recorded at fair value on the balance sheet with the corresponding unrealized gain or loss on the income statement under the caption "Commodity derivatives." For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. The hedging relationship between the hedging instruments and hedged items, such as oil and gas, must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. We measure hedge effectiveness at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, or in the case of options based on the change in intrinsic value. A regression analysis is used to determine whether the relationship is considered to be highly effective retrospectively and prospectively. Actual effectiveness of the hedge will be calculated against the underlying cumulatively using the dollar offset method at the end of each quarter. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss, such as time value for option contracts, is recognized immediately in the statements of income. Gains and losses on hedging instruments and adjustments of the carrying amounts of hedged items are included in revenues for hedges related to our crude oil and natural gas sales and in operating expenses for hedges related to our natural gas consumption. The resulting cash flows are reported as cash flows from operating

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

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

activities. See Note 15 - Hedging.

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

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

Oil and gas properties, buildings and equipment - We account for our oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion and the related capitalized costs are reviewed quarterly. Exploratory wells that discover potentially economic reserves that are in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized if the well found a sufficient quantity of reserves to justify its completion as a producing well and we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The costs of development wells are capitalized whether productive or nonproductive.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**3. Fair Value of Financial Instruments**

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

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

**4. Concentration of Credit Risks**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Includes cogeneration facility costs.

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

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

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

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

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

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

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

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

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

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

	2005	2004
Proforma Revenue	\$ 408,088	\$ 295,243
Proforma Income from operations	190,970	121,688
Proforma Net income	112,660	72,393
Proforma Basic earnings per share	5.11	3.31
Proforma Diluted earnings per share	5.01	3.22

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

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

***Suspended Well Costs***

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

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

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

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

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

***Dry hole, abandonment and impairment***

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

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

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

***Long-term debt***

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

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

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

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

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

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

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

**Short-term debt**

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

**7. Shareholders' Equity**

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

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital Stock," are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a \$.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Common Stock at the option of the holder.

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

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

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

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

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

**Dividends**

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

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

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

**Shareholder Rights Plan**

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

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

**8. Asset Retirement Obligations**

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

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

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

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

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

**9. Income Taxes**

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

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

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

	2006	2005
<b>Deferred tax asset:</b>		
Federal benefit of state taxes	\$ 4,248	\$ 2,712
Credit carryforwards	33,338	31,929
Stock option costs	3,989	2,352
Derivatives	13,275	16,253
Other, net	3,450	139
	<u>58,300</u>	<u>53,385</u>
<b>Deferred tax liability:</b>		
Depreciation and depletion	(162,560)	(102,754)
Other, net	-	(289)
	<u>(162,560)</u>	<u>(103,043)</u>
<b>Net deferred tax liability</b>	<u>\$ (104,260)</u>	<u>\$ (49,658)</u>

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

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

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

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

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

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

**10. Leases Receivable**

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

Net minimum lease payments receivable	\$ 11,511
Unearned income	<u>(2,657)</u>
Net investment in direct financing lease	<u><u>\$ 8,854</u></u>

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

2007	\$ 1,276
2008	4,545
2009	5,752
Total	<u>\$ 11,573</u>

**Drilling Rigs**

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

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

**11. Commitments and Contingencies**

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

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

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

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

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

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

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

**12. Equity Compensation Plans**

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

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

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

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

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

**Stock Options**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Restricted Stock Units**

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

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

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

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

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

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

**13. 401(k) Plan**

We sponsor a defined contribution thrift plan under section 401(k) of the Internal Revenue Code to assist all employees in providing for retirement or other future financial needs. In December 2005, the 401(k) Plan was amended whereby effective January 1, 2006, our matching contribution is \$1.00 for each \$1.00 contributed by the employee up to 8% of an employee's eligible compensation. Prior to January 1, 2006, the employer match ranged from \$1.00 to \$1.50 for each \$1.00 contributed by the employee up to 6% of an employee's eligible compensation. The employer match amount was based on the achievement of certain monthly profit levels. Our contributions to the 401(k) Plan were \$1.2 million, \$1.1 million and \$.8 million for 2006, 2005 and 2004, respectively. Employees are eligible to participate in the 401(k) Plan on their date of hire and approximately 92% of our employees participated in the 401(k) Plan in 2006.

**14. Director Deferred Compensation Plan**

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

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

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

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

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

**15. Hedging**

From time to time we enter into crude oil and natural gas hedge contracts, the terms of which depend on various factors, including management's view of future crude oil and natural gas prices and our future financial commitments. This hedging program is designed to moderate the effects of a severe crude oil price downturn and protect certain operating margins in our California operations. Currently, the hedges are in the form of swaps and collars, however we may use a variety of hedge instruments in the future. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging or other price protection is appropriate. All of these hedges have historically been deemed to be cash flow hedges with the marked-to-market valuations provided by external sources, based on prices that are actually quoted.

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

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

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

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities. At December 31, 2006, our net fair value of derivatives liability was \$33.2 million as compared to \$40.6 million at December 31, 2005. Based on NYMEX strip pricing as of December 31, 2006, we expect to make hedge payments under the existing derivatives of \$4.8 million during the next twelve months. At December 31, 2006 and 2005, Accumulated Other Comprehensive Loss consisted of \$20 million and \$ 24.4 million, respectively, net of tax, of unrealized losses from our crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at December 31, 2006. Deferred net losses recorded in Accumulated Other Comprehensive Loss at December 31, 2006 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts.

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

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

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

	Operating Revenues	Income Before Taxes	Net Income	Basic Net Income Per Share (1)	Diluted Net Income Per Share (1)
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
	<u>\$ 483,429</u>	<u>\$ 176,387</u>	<u>\$ 107,943</u>	<u>\$ 2.46</u>	<u>\$ 2.41</u>
2005					
First Quarter	\$ 87,847	\$ 33,367	\$ 22,505	\$ .51	\$ .50
Second Quarter	92,339	37,322	25,260	.57	.56
Third Quarter	109,372	48,765	34,219	.78	.76
Fourth Quarter	115,363	43,405	30,372	.69	.68
	<u>\$ 404,921</u>	<u>\$ 162,859</u>	<u>\$ 112,356</u>	<u>\$ 2.55</u>	<u>\$ 2.50</u>

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

**BERRY PETROLEUM COMPANY**

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

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

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

(1) Costs incurred for proved and unproved property acquisitions in 2005 include the reclassification of 2004 deposits of \$5,505 and \$4,716, respectively.

(2) Development costs include \$.5 million, \$.6 million and \$.7 million that were charged to expense during 2006, 2005 and 2004, respectively.

(3) Exploration costs include \$3.8 million and \$3.6 million that were charged to expense during 2006 and 2005, respectively. Exploration costs include \$9.3 million of capitalized interest.

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

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

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

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

**BERRY PETROLEUM COMPANY**

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

**Changes in estimated reserve quantities**

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

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

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

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

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

	2006	2005	2004
Future cash inflows	\$ 6,195,547	\$ 6,088,170	\$ 3,281,155
Future production costs	(2,497,785)	(2,297,638)	(1,405,432)
Future development costs	(511,886)	(333,722)	(216,859)
Future income tax expenses	(892,669)	(1,115,516)	(355,764)
Future net cash flows	2,293,207	2,341,294	1,303,100
10% annual discount for estimated timing of cash flows	(1,110,939)	(1,089,914)	(616,352)
Standardized measure of discounted future net cash flows	<u>\$ 1,182,268</u>	<u>\$ 1,251,380</u>	<u>\$ 686,748</u>
Average sales prices at December 31:			
Oil (\$/Bbl)	\$ 46.15	\$ 48.38	\$ 29.49
Gas (\$/Mcf)	\$ 4.45	\$ 7.91	\$ 6.61
BOE Price	\$ 41.23	\$ 48.21	\$ 29.87

**BERRY PETROLEUM COMPANY**

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

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

	2006	2005	2004
Standardized measure - beginning of year	\$ 1,251,380	\$ 686,748	\$ 528,220
Sales of oil and gas produced, net of production costs	(300,619)	(240,039)	(144,457)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	(350,877)	702,867	190,861
Revisions of previous quantity estimates	(7,359)	5	40,419
Improved recovery	158,213	12,267	18,787
Extensions and discoveries	227,348	168,291	26,541
Change in estimated future development costs	(333,663)	(157,068)	(56,314)
Purchases of reserves in place	33,390	103,150	962
Sales of reserves in place	-	(9,613)	(1,043)
Development costs incurred during the period	277,075	111,613	65,971
Accretion of discount	125,138	87,650	68,312
Income taxes	109,918	(392,886)	(16,890)
Other	(7,676)	178,395	(21,430)
Royalties converted to working interest	-	-	(13,191)
Net increase (decrease)	(69,112)	564,632	158,528
Standardized measure - end of year	\$ 1,182,268	\$ 1,251,380	\$ 686,748

**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, 2006, 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, 2006, 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, 2006.

Management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included 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, 2006 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**

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

## **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 2006 and 2005" 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**

<b>Exhibit No.</b>	<b>Description of Exhibit</b>
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.
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 by and between the Registrant and Robert F. Heinemann (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 Stock Award Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 99.1 on Form 8-K filed on December 22, 2005, File No. 1-9735).
- 10.13\* 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).
- 10.14\* 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).
- 10.15\* 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).
- 10.16\* 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).
- 10.17\* 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).
- 10.18\* 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).
- 10.19\* Purchase and sale agreement between the Registrant and J-W Operating Company (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K/A filed on February 15, 2005, 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.
- 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 28, 2007.

**BERRY PETROLEUM COMPANY**

/s/ Robert F. Heinemann  
ROBERT F. HEINEMANN  
President, Chief Executive Officer  
and Director

/s/ Ralph J. Goehring  
RALPH J. GOEHRING  
Executive Vice President and  
Chief Financial Officer  
(Principal Financial Officer)

/s/ Steven B. Wilson  
STEVEN B. WILSON  
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 28, 2007
/s/ Robert F. Heinemann Robert F. Heinemann	President, Chief Executive Officer and Director	February 28, 2007
/s/ Joseph H. Bryant Joseph H. Bryant	Director	February 28, 2007
/s/ Ralph B. Busch, III Ralph B. Busch, III	Director	February 28, 2007
/s/ William E. Bush, Jr. William E. Bush, Jr.	Director	February 28, 2007
/s/ Stephen L. Cropper Stephen L. Cropper	Director	February 28, 2007
/s/ J. Herbert Gaul, Jr. J. Herbert Gaul, Jr.	Director	February 28, 2007
/s/ Thomas J. Jamieson Thomas J. Jamieson	Director	February 28, 2007
/s/ J. Frank Keller J. Frank Keller	Director	February 28, 2007
/s/ Ronald J. Robinson Ronald J. Robinson	Director	February 28, 2007



**DESCRIPTION OF THE SHORT-TERM CASH INCENTIVE PLAN (BONUS)**

Annual cash incentive awards, which are designed to provide short-term performance incentives, are made to employees to recognize and reward corporate and individual performance. The plan in effect provides an annual incentive fund of up to 3.75% of the Company's annual net income, with certain adjustments, to potentially any and all employees upon achievement of the Company's growth and profitability goals.

Annually, Management and the Board will set specific targets to be achieved which will determine the cash payment as a whole and then to each eligible employee based on a formula. Executive Officers have performance metrics established for each of the following: net income, production, operating expenditures, proved reserves, and finding and development costs, all modified by environmental health and safety ("EHS") performance. All other employees have performance metrics for production and EHS. The Board retains the flexibility to adjust various items to assure compliance with the intent of the cash incentive awards. All annual cash bonuses for executive officers are approved by the Compensation Committee and the Board of Directors.

**CRUDE OIL SUPPLY AGREEMENT**

**by and between**

**BERRY PETROLEUM COMPANY**

**and**

**HOLLY REFINING AND MARKETING COMPANY - WOODS CROSS**

**dated**

**February 27, 2007**

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## CRUDE OIL SUPPLY AGREEMENT

**THIS CRUDE OIL SUPPLY AGREEMENT** entered into on February 27, 2007 for performance commencing as of July 1, 2007 (the “**Effective Date**”), is made by and between Berry Petroleum Company, a Delaware corporation (“**Supplier**”), and Holly Refining & Marketing Company - Woods Cross, a Delaware corporation (“**Refiner**”). Supplier and Refiner may each be referred to hereinafter individually as a “**Party**” or collectively as the “**Parties**.”

### RECITALS:

A. **WHEREAS** Refiner is investing significant capital in order to process increased volumes of black wax crude oil at its Woods Cross refinery (the “**Refinery**”) located at Salt Lake City, in the State of Utah and is therefore interested in securing a long term supply of black wax crude oil blend for the Refinery; and

B. **WHEREAS** Supplier and Refiner have considered the mutual benefit of a long term black wax crude oil supply agreement containing price terms and volume commitments, all as set forth in this Agreement;

**NOW THEREFORE**, in consideration of the foregoing, the representations, warranties, covenants, agreements and undertakings contained in this Agreement and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

### ARTICLE 1

#### REFERENCES AND DEFINITIONS; RELATIONSHIP OF THE PARTIES

**1.1 Definitions.** Capitalized terms used in this Agreement and the Schedules hereto, unless otherwise defined herein, have the meanings given to those terms in Schedule 1.1.

**1.2 Attachments.** The following Schedules are attached to this Agreement and are incorporated into this Agreement by this reference:

Schedule 1.1	Definitions
Schedule 2.1	Quality Ranges of Crude Oil
Schedule 2.3	Delivery Point
Schedule 3.2	Quality Testing Procedures
Schedule 3.3	Measurement Procedures
Schedule 7.8	Continuing Guaranty
Schedule 11.1(a)	Continuing Guaranty (For Extension Period)

**1.3 Independent Contractor; No Partnership.** Each Party’s duties and performance under this Agreement shall be those of an independent contractor, as defined by Applicable Laws. The Parties expressly agree and acknowledge that (a) nothing in this Agreement shall be deemed to make the Parties partners or joint venturers, and (b) neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party except as expressly provided herein.

**ARTICLE 2**  
**SUPPLY, DELIVERY AND RECEIPT OF CRUDE OIL**

**2.1 Supply and Receipt of Base Daily Volumes.**

(a) During the Term and subject to Section 2.1(b), Supplier shall sell and deliver to Refiner at the Delivery Point, and Refiner shall buy and take delivery at the Delivery Point 3,200 Barrels of Crude Oil per Day (the “**Base Daily Volume**”).

(b) If Refiner has delivered to Supplier a certificate certifying that the Refinery Modification Completion has occurred, as soon thereafter as reasonably possible for Supplier to accommodate but in any event within ninety (90) Days from the date of such delivery of the certificate (or such later date as may be specified in the certificate) the Base Daily Volume shall be increased to 5,000 Barrels of Crude Oil per Day.

(c) A 50% Daily variation in the quantity of Crude Oil delivered pursuant to this Section 2.1 shall be permitted; provided that for each Month or portion thereof during the Term, the average Daily quantity delivered pursuant to this Section 2.1 shall equal the Base Daily Volume.

**2.2 Supply and Receipt of Incremental Daily Volumes.**

(a) Not later than 120 Days prior to the start of any Contract Year, Supplier may provide a notice to Refiner indicating the Daily volume of Crude Oil production in addition to the Base Daily Volumes that Supplier and its Affiliates reasonably anticipate producing during such Contract Year. Within 30 Days following receipt of such notice by Refiner, Refiner shall notify Supplier of the portion, if any, of such additional Daily volume of Crude Oil that Refiner desires to purchase. Failure to deliver such notice shall be deemed an election by Refiner not to purchase any of such additional Daily volume. Such portion, if any, that Refiner elects to purchase in its notice to Supplier shall be referred to herein as the “**Incremental Daily Volume**”. For the Contract Year immediately following such notice from Refiner, but not for the remainder of the Term following such Contract Year, Supplier shall sell and deliver to Refiner at the Delivery Point, and Refiner shall buy and take delivery at the Delivery Point each Day the Incremental Daily Volume, in addition to the Base Daily Volume.

(b) A 50% Daily variation in the quantity of Crude Oil delivered pursuant to this Section 2.2 shall be permitted; provided that for each Month or portion thereof during the Term, the average Daily quantity delivered pursuant to this Section 2.2 shall equal the Incremental Daily Volume.

**2.3 Delivery Point.** Supplier will tender delivery of all Crude Oil to be delivered to Refiner pursuant to this Agreement at the outlet flanges of Supplier’s lease tankage on wells identified on Supplier’s Uinta Basin, Utah, properties from time to time in writing by Supplier to Refiner as referenced on Schedule 2.3 (the “**Delivery Point**”). Refiner shall accept delivery of such Crude Oil at the Delivery Point.

## 2.4 Scheduling.

(a) The Parties shall coordinate to schedule the delivery and receipt of Crude Oil in accordance with the procedures and limitations of the relevant transport and delivery and receiving facilities; provided that this Section 2.4(a) shall not limit the obligations of the Parties pursuant to Sections 2.1 and 2.2.

(b) Notice of Significant Events. 180 Days in advance of any planned material events which impact the Refinery's ability to process or Supplier's ability to produce the Crude Oil to be delivered hereunder, such as a refinery turnaround or a production facility turnaround (a "**Significant Event**") the affected Party shall notify the other Party regarding schedule and volume impacts of any Significant Event that may, in the case of Refiner, reduce its processing capabilities, or in the case of Supplier, reduce its supplying capabilities, by more than 10% of the Contract Daily Volume for more than seven Days. The Parties shall use commercially reasonable efforts to reduce the adverse impacts of all Significant Events on each Party. If the required notice has been provided, the Parties obligations under Sections 2.1 and 2.2 shall be excused during any such Significant Events. Each Party agrees to keep the other Party promptly advised of all developments in the status of any Significant Event. No Significant Event shall be scheduled during the Term which has the effect of reducing the Base Annual Volume in any one 12 month period by more than 10%.

2.5 Dedication of Production. Supplier will dedicate its (and its Affiliates') first production of Crude Oil to satisfy the requirements of this Agreement. Without limiting the foregoing, Supplier agrees that any agreements by Supplier or its Affiliates to sell Crude Oil to a purchaser other than Refiner shall be satisfied only out of production in excess of the volumes to be sold to Refiner pursuant to this Agreement. In the event Supplier elects to market its production in excess of the Base Daily Volumes and Refiner chooses to bid for such volumes, Supplier will contract to sell the incremental volumes to Refiner if Refiner exceeds or matches the highest bid from other potential purchasers.

## **ARTICLE 3** **QUALITY AND MEASUREMENT**

### 3.1 Quality.

(a) The crude oil delivered to Refiner shall conform to the Minimum Quality Specifications ("**Crude Oil**"). Without limiting any other provision of this Agreement, in no event shall Supplier inject any unsaturated stock or vis-broken stock, LPG, Natural Gasoline or Lube Oils as a part of Crude Oil delivered under this Agreement. If Refiner deems the quality of Crude Oil delivered pursuant to this Agreement to be inconsistent with Prudent Industry Practices, Supplier and Refiner shall work together to develop additional delivered quality management processes and specifications. If Supplier and Refiner are unable to develop such additional processes and specifications, the matter shall be resolved by arbitration in accordance with Section 13.7.

(b) Supplier warrants that the Crude Oil delivered to the Refiner conforms to the minimum specifications set forth in Schedule 2.1 (the “**Minimum Quality Specifications**”) and is not contaminated by any foreign chemicals.

3.2 Evidence of Quality. For purposes of determining whether the crude oil delivered pursuant to this Agreement meets the Minimum Quality Specifications, Refiner will have 30 Days from the date that a delivery arrives at the Refinery to notify Supplier that it has tested the delivery and that the test results indicate that the delivery did not meet the Minimum Quality Specifications. Supplier will have 30 Days from receipt of such notification to provide the results of sample analysis performed by a reputable independent third party testing service using the testing methods described in Schedule 3.2. Any rejection of volumes or price adjustment will be based on such injection sample test results.

3.3 Measurement. Measurement of Crude Oil shall be in accordance with the measurement procedures set forth on Schedule 3.3.

3.4 Observation. Each Party shall have the right to have a representative witness all gauges, tests, or measurements performed in connection with this Agreement providing that reasonable advance notice is given. In the absence of the other party’s representative, such gauges, tests, and measurements shall be deemed to be correct absent manifest error.

#### **ARTICLE 4** **PRICING**

4.1 Pricing Formula. The price (the “**Price Formula**”) for Crude Oil delivered pursuant to this Agreement shall be set as follows:

- (a) The price for Base Daily Volumes (US\$/Barrel) shall equal \*\*\* multiplied by WTI, Cushing (US\$/Barrel).
- (b) The price for Incremental Daily Volumes (US\$/Barrel) shall equal \*\*\* multiplied by WTI, Cushing (US\$/Barrel).

4.2 Non-Conforming Batch. If Supplier supplies a delivery which does not meet the Minimum Quality Specifications, Refiner shall be entitled either to reject such volumes (in which case Supplier shall be responsible for the costs associated with the redelivery to Supplier of such volumes) or to accept such volumes. In either case, the Parties agree to execute a price adjustment for volumes delivered in the non-conforming delivery, including a full refund of the purchase price and associated costs (e.g., transportation costs) incurred by Refiner for volumes that are rejected.

4.3 Change of Conventional Light Sweet Benchmark. The Parties agree that WTI, Cushing is intended to measure the fair market value of conventional light sweet crude oil on a North American based futures exchange. If at any time in the future WTI, Cushing ceases to be representative of the North American conventional light sweet crude oil markets, the Parties agree to determine a new light sweet crude oil benchmark for use in the Price Formula. In the event of such a cessation, either Party may declare an initiation date for the process of adjusting the Price Formula by giving notice to the other Party. The new benchmark shall be based on a

North American futures contract, if such contract exists. The Price Formula will be adjusted for quality, transportation and location for the new benchmark using the process outlined below:

(a) Compare Historical Period Average Prices for the current benchmark versus the proposed new benchmark to determine a linear correlation ( $y=mx$ ) between the fair market values of the current benchmark versus the proposed new benchmark and apply this correlation to the Price Formula.

(b) After transition to the new light crude benchmark and establishing the revised Price Formula, either Party may request a review of the Price Formula after the elapse of 6 Months. Any changes to the Price Formula resulting from the review shall be effective immediately after the review is complete and agreed by both Parties. The review results shall not have any retroactive effect and only one review period shall be permitted during the Term.

## ARTICLE 5

### TERM

5.1 Term. This term of this Agreement (“**Term**”) commences at midnight, Applicable Time, on the Effective Date, and expires at midnight, Applicable Time, on the date of termination provided in Section 11.1.

## ARTICLE 6

### TITLE; RISK OF LOSS

6.1 Title Warranty. Supplier warrants that (a) all crude oil delivered pursuant to this Agreement will be free from encumbrances and other adverse interests and (b) Supplier has the right to sell and pass title to Refiner of all such crude oil.

6.2 Disclaimer. EXCEPT AS SPECIFICALLY PROVIDED IN SECTIONS 3.1(b), 6.1 AND ARTICLE 8, SUPPLIER MAKES NO, AND HEREBY DISCLAIMS ANY, REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, STATUTORY OR OTHERWISE, ABOUT OR RELATING TO THE CRUDE OIL DELIVERED BY IT HEREUNDER INCLUDING, WITHOUT LIMITATION, WARRANTIES AS TO CONDITION, QUALITY, MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, OR OTHERWISE.

6.3 Transfer of Title and Associated Risks Warranty. Title, custody and risk of loss to Crude Oil delivered hereunder shall pass from Supplier to Refiner when Supplier delivers Crude Oil to Refiner at the Delivery Point, it being understood and agreed that any casualty, loss, escape or contamination occurring before and to the Delivery Point shall be the responsibility of Supplier and after the Delivery Point shall be the responsibility of Refiner. Except as otherwise provided in this Agreement, Refiner shall be responsible for arranging and paying for all transportation from the Delivery Point to the Refinery.

**ARTICLE 7**  
**PAYMENTS, INVOICES AND CREDIT REQUIREMENTS**

7.1 Payment Per Warranty. Refiner agrees to pay Supplier the Purchase Price for each Barrel of Crude Oil Supplier delivers to the Delivery Point pursuant to this Agreement.

7.2 Monthly Invoices Warranty. Supplier shall invoice Refiner for Crude Oil delivered pursuant to this Agreement, on a Monthly basis. Such invoice shall include the following information: the Month of delivery under the transaction; the volume(s) of delivery; the Purchase Price; and the due date of payment pursuant to Section 7.4.

7.3 Necessary Documents Warranty. Upon request, each Party agrees to furnish the other Party all source documents for each volume of crude oil delivered pursuant to this Agreement that are reasonably available to the furnishing Party; provided that furnishing source documents shall not be a precondition for payment unless expressly so agreed by the Parties. Source documents include delivery tickets, transfer settlements, or other shipping/loading documents provided by a pipeline or other carrier indicating the type, quality, volume, and other characteristics of the crude oil delivered.

7.4 Payment of Invoices Warranty. Refiner shall pay all amounts owed by it hereunder by electronic funds transfer to Supplier's account designated in Section 13.3(c) with immediately available funds by the later of the 5th Business Day after the applicable invoice was received or the 20th Day of the Month following the Month of crude oil delivery. If payment falls due on a Saturday or a bank holiday of the bank where the designated account is located other than Monday, payment shall be due on the preceding banking day of such bank. If payment falls due on a Sunday or a Monday bank holiday of such bank, payment shall be due on the next banking day of such bank. Payment shall be deemed made on the date good funds are credited to Supplier's account at such bank.

7.5 Late Payments. Any payments that are not made when due under this Agreement pursuant to Section 7.4 shall bear interest at a per annum rate which shall be two percentage points above the U.S. prime rate as published in the Wall Street Journal (or such other publication as the parties may agree from time to time) in effect on the date payment was due from the date such payment is due until such payment is made paid in full.

7.6 Corrections; Disputes. Invoices and payments shall be subject to correction for billing errors for a period of 24 Months after the end of the Month prior to which the invoice was issued. No adjustment or correction shall be made and all records and payments shall be conclusively presumed to be final and shall not be subject to examination, unless notice specifying the error or inaccuracy is given within such 24-Month period. If Refiner disputes the correctness of any invoice, Refiner shall nevertheless pay the full amount of the invoice (including the disputed portion) and shall notify Supplier of the specific basis for disputing the correctness of the invoice as soon as practical after becoming aware of the basis for the dispute, and Refiner shall be entitled to a refund for overpayments plus interest at the rate described in Section 7.5 calculated from the date of payment until refunded.

7.7 Financial Responsibility. Notwithstanding anything in this Agreement, if at any time, Parent has a net worth of less than \$200,000,000 or should Supplier reasonably believe that such Parent's net worth is less than \$200,000,000, Supplier may at anytime require, by written notice to Refiner, at Refiner's choice, either 1) advance cash payment, or 2) satisfactory security in the form of a letter or letters of credit at Refiner's expense in a form and from a bank reasonably acceptable to Supplier, to cover any and all deliveries of Crude Oil. If, on or before the date specified in Supplier's notice under this Section 7.7, Refiner does not prepay or provide the letter or letters of credit, or if Supplier does not accept another form of credit assurance agreeable to Supplier in Supplier's sole discretion, Supplier may terminate this Agreement immediately and Refiner shall be considered to experience an Event of Default. At any time Parent has a net worth of less than \$200,000,000 or if Supplier reasonably believes that such net worth is less than \$200,000,000, Seller shall not be obligated to schedule or complete delivery of the Crude Oil until advance cash payment is made or said letter or letters of credit, or if applicable, other credit assurance agreeable to Supplier, is delivered by Refiner to Supplier. In any event if Parent or Refiner makes an advance cash payment to Supplier, so long as Refiner is not in default, Supplier will deposit said cash payment into an interest bearing investment earning interest at a rate equivalent to the equivalent yield of a thirty (30) day U.S. Treasury note and such earned interest shall be held for the benefit of Parent or Refiner.

7.8 Continuing Guaranty. As a material condition to this Agreement, Refiner shall concurrently deliver to Supplier a Continuing Guaranty, in the form attached to this Agreement as Schedule 7.8.

## **ARTICLE 8**

### **REPRESENTATIONS AND WARRANTIES**

8.1 Supplier Representations and Warranties. Supplier represents and warrants to Refiner that:

(a) It is duly organized, validly existing and in good standing under the laws of Delaware, and has all requisite power and authority to own and lease the properties and assets it currently owns and leases, and to conduct its activities as such activities are currently conducted and as contemplated by this Agreement;

(b) Supplier has all requisite corporate power, authority and capacity to execute, deliver and perform this Agreement and to consummate the transactions contemplated hereby. The execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby by Supplier have been duly and validly authorized by all necessary corporate action on its part, and this Agreement has been duly and validly executed and delivered by Supplier, and is the valid and binding obligation of Supplier, enforceable against it in accordance with its terms, subject to Applicable Laws of bankruptcy, insolvency and similar laws affecting creditors' rights and remedies generally;

(c) The execution, delivery and performance by Supplier of this Agreement does not and will not (i) conflict with or violate any provision of Supplier's organizational documents; (ii)

violate any provision of any Applicable Laws; (iii) conflict with, violate, result in a breach of, constitute a default under (without regard to requirements of notice, lapse of time or elections of other Persons, or any combination thereof) or accelerate or permit the acceleration of the performance required by, any contracts or other instruments to which either Supplier is a party or by which Supplier is bound or affected; or (iv) require any consent, approval or authorization of, or filing of any certificate, notice, application, report, or other document with, any Governmental Authority or other Person;

(d) Supplier is not subject to any Applicable Law that would preclude or prohibit its fulfillment of any of its obligations hereunder, all in accordance with the terms and conditions of this Agreement; and

(e) Supplier has the requisite authority, ability, skills, technical support and capacity to perform all of its obligations hereunder with respect to the supply of Crude Oil and the operation of its production facilities, all in accordance with this Agreement in all material respects.

**8.2 Refiner Representations and Warranties.** Refiner represents and warrants to Supplier that:

(a) Refiner is duly organized, validly existing and in good standing under the laws of Delaware and has all requisite power and authority to own and lease the properties and assets it currently owns and leases and to conduct its activities as such activities are currently conducted and as contemplated by this Agreement;

(b) Refiner has all requisite corporate power, authority and capacity to execute, deliver and perform this Agreement and to consummate the transactions contemplated hereby. The execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby by Refiner have been duly and validly authorized by all necessary action on the part of Refiner, and this Agreement has been duly and validly executed and delivered by Refiner, and is the valid and binding obligation of Refiner, enforceable against Refiner in accordance with its terms, subject to Applicable Laws of bankruptcy, insolvency and similar laws affecting creditors' rights and remedies generally;

(c) The execution, delivery and performance by Refiner of this Agreement do not and will not (i) conflict with or violate any provision of its organizational documents; (ii) violate any provision of any Applicable Laws; (iii) conflict with, violate, result in a breach of, constitute a default under (without regard to requirements of notice, lapse of time or elections of other Persons, or any combination thereof) or accelerate or permit the acceleration of the performance required by, any contracts or other instruments to which it is a party or by which it or its properties may be bound or affected; or (iv) except in connection with the construction and operation of the Refinery Modifications, require any consent, approval or authorization of, or filing of any certificate, notice, application, report or other document with, any Governmental Authority or other Person;

(d) Subject to obtaining any approvals from Governmental Authorities required to construct and operate the Refinery Modifications, Refiner is not subject to any Applicable Law

that would preclude or prohibit any of its obligations hereunder, all in accordance with the terms and conditions of this Agreement; and

(e) Refiner has the requisite authority, ability, skills, technical support and capacity to perform all of its obligations hereunder, all in accordance with this Agreement in all material respects.

**ARTICLE 9**  
**EVENTS OF DEFAULT; REMEDIES; LIMITATION ON DAMAGES**

**9.1 Events of Default.** An event of default (“**Event of Default**”) with respect to a Party (the “**Defaulting Party**”) shall mean any of the following:

(a) the failure of Defaulting Party to pay when due any payment under this Agreement, and such payment (and any interest accrued thereon pursuant to this Agreement) shall remain unpaid for 10 Days following receipt by the Defaulting Party of notice of failure to pay; or

(b) the failure of the Defaulting Party to comply in any material respect with any of its other obligations under this Agreement, and such failure is not remedied in all material respects within 30 Days after notice thereof; or

(c) any representation or warranty made by the Defaulting Party under this Agreement is or was untrue or misleading in any material respect when made and such breach is not cured within 30 Days after notice thereof; or

(d) the entry of a decree or order by a court having jurisdiction in the premises resulting from the commencement of proceedings against the Defaulting Party by a third party and approving as properly filed a petition seeking dissolution or winding-up of the Defaulting Party under any bankruptcy, insolvency or analogous laws, or appointing a receiver of the Defaulting Party, and the continuance of any such decree or order unstayed, undischarged and in effect for a period of 20 Days from the date thereof; or

(e) the institution by the Defaulting Party of proceedings to be adjudicated a bankrupt or insolvent, or the consent by it to the institution of bankruptcy or insolvency proceedings against it, or the filing by it of a petition, answer or consent seeking dissolution or winding-up under any bankruptcy, insolvency or analogous laws, or the consent by it to the filing of any such petition or to the appointment of a receiver of the Defaulting Party or the making by it of a general assignment for the benefit of creditors, or the Defaulting Party admitting in writing its inability to pay its debts generally as they become due.

**9.2 Remedies.** Upon the occurrence and during the continuation of an Event of Default as to the Defaulting Party, the other Party (the “**Non-Defaulting Party**”) may, in its sole discretion, (a) notify the Defaulting Party of an early termination date (which shall be no earlier than the date of such notice and no later than 30 Days after the date of such notice) on which date this Agreement shall terminate and declare that any amounts of money outstanding hereunder shall be due and payable immediately without any further notice or demand of any kind or (b) withhold performance of any of its obligations due to the Defaulting Party until such Event of

Default is cured. Any rights of a Nondefaulting Party under this Section 9.2 shall be in addition to any other rights or remedies such Nondefaulting Party may have under this Agreement, at law or in equity.

9.3 Right of Set-Off Warranty. Upon the occurrence and during the continuance of an Event of Default, the Non-Defaulting Party is hereby authorized at any time and from time to time thereafter, on reasonable notice to the Defaulting Party and to the fullest extent permitted by law, to set-off and apply any and all indebtedness at any time owing by the Non-Defaulting Party to or for the credit or the account of the Defaulting Party against any and all of the obligations of the Defaulting Party now or hereafter existing under this Agreement. The Non-Defaulting Party agrees to promptly notify the Defaulting Party after any such set-off and application.

9.4 Limitation on Damages. Liability for breach of any provision of this Agreement is limited to actual direct damages only (which in the case of a failure by Supplier to deliver Crude Oil that is not permitted by this Agreement shall be deemed to include lost margins on Refinery production and other costs (e.g., transportation costs) incidental to such failure), and such actual direct damages are the sole and exclusive monetary remedy under this Agreement for any such breach. Except as provided in the preceding sentence, neither Party is liable for incidental, punitive, exemplary, consequential, special or indirect damages of any nature (including damages associated with lost profits, business interruption and loss of goodwill) arising at any time, whether in tort (including negligence or gross negligence), warranty, strict liability, by contract or statute, under any indemnity provision (unless such damages are required to be paid to a third party) or otherwise.

## **ARTICLE 10**

### **FORCE MAJEURE**

10.1 General. Notwithstanding anything herein to the contrary, each Party shall be excused from performance of its obligations hereunder (other than any obligation to pay money then due or becoming due with respect to performance prior to the event) in the event and to the extent its performance is prevented by an event of Force Majeure.

10.2 Notice Requirements Warranty. If an event of Force Majeure occurs, the Party whose performance is prevented shall promptly provide notice to the other Party of the event of Force Majeure, the nature of the event, the extent to which the event of Force Majeure affects or delays the affected Party's performance hereunder, the particular obligations so affected, the steps taken and proposed to be taken to lessen and cure the Force Majeure, and the estimated duration of the event of Force Majeure. If there is any material change, addition or alteration to the circumstances giving rise to, or the information provided pursuant to, the notice, the affected Party shall promptly provide the other Party with notice of the same.

10.3 Efforts to Remove Force Majeure. At all times during an event of Force Majeure, both Parties shall use commercially reasonable efforts to remove the event of Force Majeure and to avoid or minimize the consequences of the event of Force Majeure; provided that nothing contained in this Agreement shall be construed as requiring either Party hereto to accede to the demands of labor or labor unions it considers unreasonable in its sole discretion. The

performance of this Agreement shall be resumed as soon as practicable after such disability has been removed.

## **ARTICLE 11** **TERMINATION**

**11.1** **Termination.** This Agreement shall terminate on the earliest of:

(a) **Expiration of Primary Term.** The date that is the six year anniversary of the Effective Date; provided that a Party has provided notice of such termination to the other Party at least 120 Days prior to the expiration of such period; provided further that the termination date shall automatically be extended for one additional year if such notice is not provided, and for additional one-year periods if such notice is not provided at least 120 Days prior to the end of each such one-year extension. In the event of an extension for an additional year, no later than 60 days prior to the beginning of any such extension, Supplier may request that Refiner provide to Supplier a Continuing Guaranty (For Extension Period) substantially in the form attached hereto as Schedule 11.1(a), for such additional year. If Refiner does not provide such a guaranty within 30 Days after such request, such extension shall not be effective and this Agreement shall terminate at the end of the current term;

(b) **Event of Default.** The date on which either Party terminates this Agreement pursuant to **Section 9.2;**

(c) **Force Majeure.** The date on which the applicable Party terminates this Agreement pursuant to **Section 11.3,** by providing notice of such termination to the other Party;

(d) **Processes and Specifications.** The date on which Refiner terminates this Agreement pursuant to **Section 3.1(a),** by providing notice to Supplier; and

(e) **Change in Law.** In the event of a change in Applicable Laws that Refiner reasonably determines will have an adverse effect on anticipated refinery economics using LP analysis and industry practice, the date indicated in a notice by Refiner to Supplier; provided that such termination date shall not be sooner than 180 days following the date of such notice. Whether or not Refiner's determination satisfies the standard set forth in this Section 11.1(e) shall be subject to arbitration under Section 13.7.

**11.2** **Effect of Termination.** Termination of this Agreement for any reason shall not affect: (i) each Party's obligation to perform its obligations arising hereunder prior to such termination, (ii) each Party's indemnification and defense obligations and any other duties of either Party which by their nature are to be performed after termination of this Agreement, or (iii) damages as a result of an Event of Default.

**11.3** **Termination for Extended Force Majeure.** If an event of Force Majeure claimed by Refiner or Supplier persists for a continuous period of at least 180 Days or if the duration of an event of Force Majeure claimed by Refiner or Supplier is reasonably estimated by the Party claiming Force Majeure to be at least 180 Days, then the Party not claiming the Force Majeure shall have the right, but not the obligation, to terminate this Agreement by giving notice of termination to the other Party. For purposes of this **Section 11.3,** if the period between the end of

one event of Force Majeure and the commencement of another event of Force Majeure is less than 30 Days, the period of Force Majeure shall be deemed to be continuous, but the time between the Force Majeure periods shall not be counted in determining the 180-Day period required before termination hereunder is allowed.

## **ARTICLE 12** **INDEMNIFICATION AND DAMAGES**

**12.1 Refiner's Indemnification Obligations.** Refiner agrees to indemnify, defend and hold harmless Supplier Indemnified Parties from and against any and all Claims arising out of, relating to or in connection with:

(a) Any injury or death of persons or damage to property arising out of, relating to, or in connection with, the transportation, carriage, handling, care, storage, resale or use of the crude oil sold hereunder after delivery to Refiner at the Delivery Point, except to the extent arising out of a Supplier Indemnified Party's gross negligence or willful misconduct; and

(b) Any breach by Refiner of any of its representations, warranties, covenants, agreements or obligations herein.

**12.2 Supplier's Indemnification Obligations.** Supplier agrees that it shall indemnify, defend and hold harmless Refiner Indemnified Parties from and against any and all Claims arising out of, relating to, or in connection with:

(a) Any injury or death of persons or damage to property arising out of, relating to, or in connection with, the production, transportation, carriage, handling, care, storage, resale or use of the crude oil sold hereunder until delivery to Refiner at the Delivery Point except to the extent arising out of a Refiner Indemnified Party's gross negligence or willful misconduct; and

(b) Any breach by Supplier of any of its representations, warranties, covenants, agreements or obligations herein.

**12.3 EXPRESS NEGLIGENCE. EXCEPT AS EXPRESSLY PROVIDED OTHERWISE ABOVE, THE FOREGOING INDEMNITIES SET FORTH IN THIS ARTICLE 12 ARE INTENDED TO BE ENFORCEABLE AGAINST THE PARTIES REGARDLESS OF THE SIMPLE OR GROSS NEGLIGENCE (WHETHER SOLE, CONCURRENT, ACTIVE OR PASSIVE) OR OTHER FAULT OR STRICT LIABILITY OF ANY INDEMNIFIED PARTIES.**

## **ARTICLE 13** **GENERAL PROVISIONS**

**13.1 Confidentiality.** Neither this Agreement nor information or documents that come into the possession of a Party or its Affiliates in connection with the performance of this Agreement may be used or communicated to Persons (other than the Parties and their Affiliates) without the mutual written agreement of the Parties, except that either Party shall have the right to disclose such information or documents without obtaining the other Party's prior consent in any of the situations described below:

(a) Accountants, bankers, other professional consultants or underwriters, provided such disclosure is solely to assist the purpose for which the aforesaid were so engaged and further provided that such Persons agree to hold such information or documents under terms of confidentiality equivalent to this Section 13.1 and for the benefit of the Parties;

(b) To legal counsel, provided such disclosure is solely to assist the purpose for which the aforesaid were so engaged;

(c) Prospective assignees of a Party's interest under this agreement or Persons potentially providing financing to a Party, provided that such Persons agree to hold such information or documents under terms of confidentiality equivalent to this Section 13.1 and for the benefit of the Parties;

(d) If required by any court of law or any Applicable Law, or if requested by a Governmental Authority having or asserting jurisdiction over a Party and having or asserting authority to require such disclosure in accordance with that authority, or pursuant to the rules of any recognized stock exchange or agency established in connection therewith;

(e) If required, in the reasonable good faith judgment of the disclosing Party, as a response to any environmental or other emergency; and

(f) To the extent any such information or document has entered the public domain other than through the fault or negligence of the Party receiving the information.

13.2 Consultation as to Announcements. Without limiting Section 13.1, no public announcement or press release concerning the transactions contemplated by this Agreement shall be made by either Party without prior consultation with the other Party; provided that such consultation shall not be required for any public announcement or press release required to be made: (a) under Applicable Law; or (b) by the reasonable good faith judgment of the disclosing Party as a response to any environmental or other emergency; provided further that all such consultations and reviews shall be completed within 24 hours of either Party seeking the other's consultation, a disclosing Party shall be under no obligation to accept the consulting Party's comments or requirements, and after 24 hours the disclosing Party shall be entitled to make the proposed disclosure if permitted by Section 13.1.

### 13.3 Notices.

i) Addresses. All notices, requests, waivers, consents, approvals, agreements and other communications under this Agreement shall, except as expressly provided otherwise herein, be in writing to be effective and shall be delivered in person or by certified mail with postage prepaid and return receipt requested, courier or overnight delivery service with charges prepaid or facsimile transmission, and if to Supplier, addressed as follows:

Berry Petroleum Company  
Attention: Manager of Marketing  
5201 Truxtun Avenue, Suite 300  
Bakersfield, CA 93309

Fax No. (661) 616-3882;

Copy to:

Musick Peeler & Garrett LLP  
Attn: Laura K. McAvoy, Esq.  
2801 Townsgate Road, Suite 200  
Westlake Village, CA 91361  
Fax No. (805) 418-3101

and if to Refiner, addressed as follows:

Holly Refining & Marketing Company - Woods Cross  
Attention: [--]  
100 Crescent Court  
Suite 1600  
Dallas, Texas 75201  
Fax No. 214-871-3560

Copy to:  
Office of General Counsel  
100 Crescent Court  
Suite 1600  
Dallas, Texas 75201.

Either Party shall have the right to change its address by notice to the other Party at the addresses in force hereunder.

(b) Effectiveness of Notices. Any communications addressed as described above shall be deemed to have been received as follows:

(i) If delivered in person, when delivered;

(ii) If delivered by facsimile, on the date of transmission thereof as reflected on the confirmation of the transmitting machine if such confirmation reflects transmission of such facsimile prior to 5:00 P.M., Applicable Time, on a Business Day; provided that if any such confirmation reflects that such transmission occurred after 5:00 P.M., Applicable Time, on a Business Day or any time on a non-Business Day, such communication shall be deemed to have been received on the next Business Day;

(iii) If delivered by certified mail, on the third Business Day following the date of mailing as shown on the certified mail receipt; and

(iv) If delivered by overnight delivery service, on the Business Day on which it is actually delivered by such delivery service as shown on the receipt provided to the delivering Party by the overnight delivery service or the next Business Day if delivered on a non-Business Day.

(c) Wire Transfer Information. Wire transfers to Supplier shall be made in accordance with the following instructions:

**Berry Petroleum Company**  
**Wells Fargo Bank**  
**Denver, CO**  
**ABA Routing No./ Transit Number: \*\*\***  
Account No.: \*\*\*.

Any questions regarding wire transfers to Supplier should be directed to:

**Berry Petroleum Company**  
Attn: Treasurer  
Phone: (661) 616-3809  
Facsimile: (661) 616-3884.

Supplier shall have the right to change the information provided in this Section 13.3(c) by notice in accordance with Section 13.3(a).

(d) Wire transfers to Refiner shall be made in accordance with the following instructions:

**Holly Refining & Marketing Company**  
Bank of America  
Charlotte, North Carolina  
ABA Routing No. \*\*\*  
Account No.: \*\*\*

Any questions regarding wire transfers to Supplier should be directed to:

**Holly Refining & Marketing Company - Woods Cross**  
Attn: Steve Wise, Treasurer  
Phone: 214-871-3877  
Facsimile: 214-237-3051.

Refiner shall have the right to change the information provided in this Section 15.3(d) by notice in accordance with Section 15.3(a).

13.4 Taxes. Refiner shall pay, without duplication, and be responsible for all sales taxes assessed as a result of the sale of crude oil hereunder imposed or assessed on itself or Supplier as a result of this Agreement but, for the avoidance of doubt, shall not be responsible for any income, severance, ad valorem or other taxes imposed on Supplier.

13.5 Headings and References.

(a) Headings. The headings are inserted for convenience only and are to be ignored in construing this Agreement.

References. References to articles, sections or paragraphs are to articles, sections or paragraphs of this Agreement. The words “hereto,” “herein,” “hereof,” “hereunder,” “this Agreement” and similar expressions mean and refer to this Agreement as a whole and not to any particular portion or provision of this Agreement.

13.6 Rules of Interpretation.

- (a) The singular includes the plural and vice versa.
- (b) Except as otherwise expressly provided herein, all references to “\$” or money mean Dollars and all payments hereunder or pursuant hereto shall be made in Dollars.
- (c) The words “include,” “includes” and “including” shall be deemed to be followed by the words “without limitation.”
- (d) If a conflict or inconsistency exists between any exhibit or schedule and this Agreement (exclusive of the exhibits and schedules), the provisions of this Agreement (exclusive of the exhibits and schedules) shall control. If any conflict or inconsistency exists between or among the exhibits and schedules, the exhibit or schedule dealing with the matter in more detail shall control.
- (e) Except as otherwise expressly provided herein, all references in this Agreement to contracts, agreements and other documents shall be deemed to refer to such contracts, agreements and other documents, as amended, modified and supplemented from time to time.
- (f) Except as otherwise expressly provided herein, all references to any Applicable Law is a reference to such Applicable Law as amended, modified or re-enacted from time to time and any replacements thereof.

13.7 Resolution of Disputes - Negotiation and Arbitration

- (a) Negotiation Period. The Parties shall endeavor in good faith to negotiate a settlement of any and all disputes arising out of or related to this Agreement, its performance, validity or the breach or termination of this Agreement, regardless of whether such dispute is based on common law, contractual or statutory causes of action, including tort claims (each a “**Dispute**”).
- (b) Initiation of Arbitration. The pre-arbitration negotiation process provided in the foregoing Section 13.7(a) is to be considered a settlement negotiation for the purposes of all state and federal rules protecting disclosures made during such negotiations from later discovery or use in evidence. If a Dispute is not resolved within 45 Days after either Party first notifies the other of the Dispute in a written request for negotiations, or such later date as may be mutually agreed by the Parties, then each Party shall have the right at any time thereafter to refer the Dispute to binding arbitration under the International Institute for Conflict Prevention and Resolution Rules for Non-Administered Arbitration (the “**Rules**”) then in force, to the extent such Rules are not inconsistent with the provisions of this Agreement.

(c) Selection of Arbitrators. The arbitral panel shall be composed of three arbitrators (the “**Tribunal**”). With the request for arbitration, the Party requesting arbitration (the “**Claimant**”) shall appoint one arbitrator. The Party named as respondent by the Claimant (the “**Respondent**”) shall appoint one arbitrator within the time specified in the Rules. The two arbitrators nominated by the Claimant and Respondent shall together nominate the third arbitrator, who shall be the chairman of the Tribunal, by mutual agreement within 20 Days of the second appointment of an arbitrator. If within the time specified a Party fails to nominate its party-appointed arbitrator or the two party-appointed arbitrators fail to nominate the third arbitrator, either party may request the CPR to make the appointment according to the Rules. If any nominated arbitrator is not appointed, declines, resigns, becomes incapacitated, or otherwise refuses or fails to serve or to continue to serve as an arbitrator, the Party or arbitrators entitled to appoint that arbitrator shall promptly nominate a successor. If the arbitrators are unable to agree on a replacement third arbitrator, then the CPR shall make the appointment according to the Rules. In the event that an arbitrator is objected to, the two remaining arbitrators shall decide whether the objection is valid and whether the challenged arbitrator shall be removed. The arbitrators shall be independent of the Parties and not have a financial interest in either of the Parties or their Affiliates or in the dispute, and shall be unaffiliated and without prior financial alliances with any Party, or either of the other arbitrators. The arbitrators shall be governed by the AAA/ABA Code of Ethics for Arbitrators in Commercial Disputes. The chairman shall be a former judge with experience in matters involving the oil and gas industry in the United States and with suitable experience of complex commercial disputes.

(d) Seat, Discovery, Hearing. The seat of the arbitration shall be Salt Lake City, Utah. The evidentiary hearing shall be transcribed by a certified court reporter. The Tribunal shall determine the appropriate procedural rules, including the admissibility of evidence, subject to any procedures specified in this Agreement or the Rules. Within twenty (20) Days after the arbitration is commenced, the Parties shall confer and attempt to agree on the disclosure of specific documents or narrowly-defined categories of documents that are reasonably expected to be material to the issues in the Dispute and the identification of persons likely to have knowledge of facts reasonably expected to be material to the issues in the Dispute. If the Parties are unable to agree on a procedure within ten (10) Days, the Tribunal may make orders to any Party to disclose the documents and/or to identify the persons described above, which the Parties consent in advance to obey. If a Party fails or refuses to comply with an order for discovery, the Tribunal may take that failure into account when deciding the issues and may infer that the evidence not produced would have supported the opposing Party’s claims. Any applicable legal privileges against disclosure shall be recognized. Within thirty (30) Days after completion of discovery, each Party shall submit by overnight delivery to the other Party and the arbitrators a precise Statement of Claims (or Counterclaims) and the factual and/or legal support therefore, including documents and statements of fact and expert witnesses. Within twenty (20) Days after receiving such statement, the other Party shall submit by overnight delivery to the first Party and the arbitrators a precise Statement of Defense to the Claims (or Counterclaims) asserted against it and the factual and/or legal support therefore, including documents and statements of fact and expert witnesses. The Tribunal shall conduct a hearing no later than ninety (90) Days following selection of the third arbitrator, or thirty (30) Days after all discovery has been completed, whichever is later.

(e) Award. The arbitrators shall consider the terms and conditions of this Agreement, and any relevant evidence and testimony, and shall render their award (the “**Award**”) within 30 Days following conclusion of the hearing. The Tribunal shall have no power to award any remedy not authorized by the governing law or barred by this Agreement, and they may not rely on any law or legal principle to avoid such limitations on remedies. The Award shall be in writing, shall give reasons for the decisions reached by the Tribunal and shall be signed and dated by the arbitrators, and a copy of the award shall be delivered to each of the Parties. The award may be made unanimously or by a majority of arbitrators. The award shall be final and binding on the parties and may be confirmed in, and judgment upon the award entered by, any court having jurisdiction over the Parties. The Tribunal’s award shall be entitled to all of the protections and benefits of a final judgment as to any Dispute, including compulsory counterclaims, that were or could have been presented to the Tribunal, and shall be final and binding on the Parties and non-appealable to the maximum extent permitted by law. The Award shall provide for interest on the Award at a per annum rate which shall be two percentage points above the U.S. prime rate as published in the Wall Street Journal (or such other publications as the arbitrators select) in effect on the date of the Award, commencing on the 31st Day following delivery of the Award to the Parties and continuing until the Award and any accrued interest is paid in full.

(f) Exclusive Method of Resolving Claims; Assistance of Courts. If a Party refuses to honor its obligations under this agreement to arbitrate, the other Party may obtain appropriate relief staying such litigation and/or compelling arbitration in any court having jurisdiction over the refusing Party; each Party hereby consenting to the non-exclusive personal jurisdiction and venue in the federal and State courts in Salt Lake City, Utah for the purpose of enforcing this Agreement. Notwithstanding Section 13.7(a), a Party may seek interim or injunctive relief from the courts to aid arbitration or preserve the status quo ante between the Parties pending the completion of the arbitration. After a Tribunal has been formed, it shall also have the power to issue interim remedies, provisional measures or partial awards as it deems appropriate. Each Party agrees that arbitration pursuant to this Section 13.7 shall be the exclusive method for resolving all Disputes and that it will not commence an action or proceeding, except as provided in this Section 13.7.

(h) Costs. The Tribunal shall have the authority to assess the costs and expenses of the arbitration proceeding (including the arbitrators’ fees and expenses) against either or both parties. Each Party shall bear its own attorneys’ fees and other legal costs; provided, however, that any costs incurred by a Party in seeking judicial enforcement of any Award shall be chargeable to and borne exclusively by the Party against whom such court order is obtained.

13.8 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Utah, U.S.A., without regard to any choice of law principles that would direct the application of the law of another jurisdiction.

13.9 Assignment; Delegation. The rights and obligations of any Party under this Agreement may not be assigned or delegated without the prior written consent of the other Party, and any assignment or delegation not in compliance with the foregoing shall be null and void, provided that, (i) either Party may assign or delegate its rights or obligations hereunder to any of its Affiliates without the other Party’s consent, provided that no such assignment or delegation

shall relieve the assigning or delegating Party from any obligation hereunder, (ii) Supplier may assign or delegate its rights or obligations hereunder without Refiner's consent in connection with the sale of all or substantially all of its Uinta Basin, Utah producing properties that produce Crude Oil and (iii) Refiner may assign or delegate its rights or obligations hereunder without Supplier's consent in connection with the sale of the Refinery; provided that, with respect to the exceptions set forth in subclauses (ii) and (iii) above the assignee or delegate must acknowledge its obligations hereunder to the nonassigning Party pursuant to an instrument reasonably satisfactory to the nonassigning Party and upon assignment the assignor shall be relieved of its obligations hereunder to be performed with respect to periods after the assignment. All covenants, terms and conditions and provisions of this Agreement shall be binding upon the Parties and shall extend to and be binding upon the successors and permitted assignees and delegates of the Parties.

13.10 Time and Performance of Essence. Time and full performance hereunder by the Parties are of the essence in this Agreement.

13.11 Nonwaiver; No Third-Party Beneficiaries. No waiver by any Party of any of its rights with respect to the other Party or with respect to any matter or default arising in connection with this Agreement shall be construed as a waiver of any subsequent right, matter or default whether of a like kind or different nature. Any waiver shall be in writing signed by the waiving Party. No Party shall be deemed to have waived, released or modified any of its rights under this Agreement unless such Party has expressly stated, in writing, that it does waive, release or modify such right. A waiver shall not be a continuing waiver unless it expressly states otherwise. This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and their permitted successors and assigns, and no other Person, other than any Persons who have explicit indemnity rights herein, shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with, this Agreement; provided that, the Parties reserve solely to themselves the power to amend or terminate this Agreement without the consent of any other Person.

13.12 Counterparts; Severability; Survival. This Agreement may be executed in several counterparts, each of which is an original and all of which constitute one and the same instrument. Each Party agrees to accept the facsimile signature of the other Party and to be bound by its own facsimile signature. Except as may otherwise be stated herein, any provision hereof that is declared or rendered unenforceable, unlawful or invalid by any Governmental Authority, or deemed unenforceable, unlawful or invalid because of a change in Applicable Law, will not otherwise affect the enforceable, lawful or valid obligations that arise under this Agreement. If any provision of this Agreement is declared unenforceable, unlawful or invalid, the Parties will promptly renegotiate to restore this Agreement as near as possible to its original intent and effect. All representations, warranties, covenants, agreements and obligations made or agreed to herein shall survive the termination of this Agreement until the expiration of the applicable statute of limitations, if any.

13.13 Expenses. Except as specifically provided herein, each Party will bear its own costs and expenses incurred in connection with or arising out of the execution, delivery or performance of this Agreement.

13.14 Further Assurances. Each of the Parties agrees to take such further actions (including the execution and delivery of such further documents and instruments) as the other Party may reasonably request after the Effective Date to fulfill the purposes of this Agreement.

13.15 Entire Agreement; Amendment; Drafting. This Agreement, including any Schedules and Exhibits hereto constitute the entire agreement among the Parties relating to the subject matter contemplated by this Agreement and supersede any prior or contemporaneous agreements or representations affecting the same subject matter. No amendment, modification or change to this Agreement shall be enforceable unless reduced to a writing executed by both Parties. The Parties acknowledge that each Party and its counsel have participated in the drafting of this Agreement and have reviewed and revised this Agreement, and that the rule of construction that any ambiguities are to be resolved against the drafting Party shall not be used in the interpretation of this Agreement.

**IN WITNESS WHEREOF**, the Parties hereto have executed this Agreement in the presence of their respective representatives duly authorized in this regard on the Day and year first above written.

**BERRY PETROLEUM COMPANY**

**HOLLY REFINING & MARKETING COMPANY - WOODS CROSS**

Per: \s\ Ralph J. Goehring

Per: \s\David L. Lamp

Name: Ralph J. Goehring

Name: David L. Lamp

Title: Executive Vice President and Chief Financial Officer

Title: President

**SCHEDULE 1.1**  
**DEFINITIONS**

In the Agreement to which this Schedule is attached and in all Schedules thereto, the following words have the meanings given to such words below:

“**Affiliate**” means any Person which, directly or indirectly, controls, is controlled by or is under common control with the applicable Party. For purposes of this definition, control of a Person means the power, direct or indirect, to direct or cause the direction of the management and policies of such Person, whether through ownership of voting securities, by contract or otherwise.

“**Agreement**” means this Crude Oil Supply Agreement, including the Schedules hereto, and any future amendments or supplements.

“**Applicable Laws**” means all applicable statutes, regulations, rules, ordinances, codes, licenses, permits, orders and approvals of each Governmental Authority having jurisdiction over the Parties or crude oil sold and delivered hereunder, including, without limitation, Environmental Laws, all health, building, fire, safety and other codes, ordinances and requirements, in each case, as amended, and any judicial or administrative interpretation thereof, including any applicable judicial order, consent, decree, sanction or judgment.

“**Applicable Time**” means the Official U.S. time for the Central Time Zone as calculated by the National Institute of Standards and Technology and the U.S. Naval Observatory (<http://www.time.gov>).

“**Award**” is defined in [Section 13.7\(f\)](#).

“**Barrel**” means, with respect to crude oil, a unit volume equivalent to (a) 42 United States standard gallons of oil, (b) 158.9118 liters or (c) 0.1590 cubic meters measured at 60 degrees Fahrenheit or 15.56 degrees Celsius.

“**Base Annual Volume**” means the Base Daily Volume multiplied by the number of Days in a Contract Year or the applicable 12 month period; provided that any change in the Base Daily Volume during such period shall only apply to the Days affected by such change.

“**Business Day**” means a Day, other than a Saturday, a Sunday or any other Day on which banking institutions in New York, New York are required or authorized to be closed.

“**Claim**” means any claim, demand, suit, action, cause of action, assessment, loss, cost, expense, Liability, judgment, fine, penalty, interest, payment, damage, including costs or expenses of any and all investigations or proceedings and reasonable fees and expenses of attorneys, accountants and other experts.

“**Contract Year**” means each 12-month period during the Term commencing with the Effective Date; provided that the final Contract Year may be less than 12-month if the Term expires prior to the expiration of the final 12-month period during the Term.

“CPR” means The International Institute for Conflict Prevention & Resolution.

“Crude Oil” is defined in [Section 3.1\(a\)](#).

“Day” means a calendar day, extending from 12:00 A.M. (Midnight) Applicable Time until 11:59 P.M. Applicable Time, and “Daily” shall have a correlative meaning.

“Defaulting Party” is defined in [Section 9.1](#).

“Delivery Point” is defined in [Section 2.3](#).

“Dispute” is defined in [Section 13.7\(a\)](#).

“Dollars” means United States dollars unless expressly provided otherwise.

“Effective Date” is defined in the preamble.

“Environmental Laws” means any one or more of the following statutes, any amendments thereto and any regulations promulgated thereunder, any similar or equivalent state laws, and any other applicable federal, state and local laws concerning pollution, protection of the environment or the use, storage, handling, treatment, management, discharge or disposal of Hazardous Materials, now existing, including, but not limited to, the: Comprehensive Environmental Response Compensation and Liability Act of 1980 (“CERCLA”), as amended by the Superfund Amendments and Reauthorization Act of 1986, 42 U.S.C. 9601 et seq.; Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (“RCRA”), 42 U.S.C. 6901 et seq.; Federal Water Pollution Control Act, 33 U.S.C. 1251 et seq.; Toxic Substances Control Act, 15 U.S.C. 2601 et seq.; Clean Air Act, 42 U.S.C. 7501 et seq.; and any similar state analogs, in each case, as amended, and any judicial or administrative interpretation thereof, including any applicable judicial order, consent, decree, sanction or judgment. Environmental Laws do not include laws relating to industrial hygiene or worker safety.

“Event of Default” is defined in [Section 9.1](#).

“Force Majeure” means an event that (a) is not within the reasonable control of the Party (or in the case of third party obligations or facilities, the third party) claiming Force Majeure (the “Claiming Party”), (b) by the exercise of due diligence, the Claiming Party (or third party) is unable to overcome or avoid or cause to be avoided and (c) prevents the Claiming Party from performing its obligations hereunder. Force Majeure may include, but is not limited to, the following events to the extent the same meet the standards set forth in clauses (a), (b) and (c) above: acts of God; act of public enemy; war; terrorism; lightning; fire; civil disturbance; labor dispute; sabotage; action or restraint by court order or Governmental Authority (so long as the Claiming Party has not applied for or assisted in the application for, and has opposed, to the extent reasonable, such government action); environmental catastrophe; inability to obtain permits or utility services or similar events or occurrences, provided that such permits or services were promptly applied for; or mechanical failures, breakdowns of or damage to the Refinery [or to more than 50% of Supplier’s producing facilities in the Uinta Basin, Utah. For the avoidance of doubt, Force Majeure shall not include the availability of a more attractive market or source..

**“Governmental Authority”** means the United States federal government or any other national government or any provincial, tribal, state, local, departmental or other political subdivision of any of the foregoing, or any entity, body or authority exercising executive, legislative, judicial, regulatory, administrative or other governmental functions or any court, department, commission, board, bureau, agency, instrumentality or administrative body of any of the foregoing.

**“Hazardous Materials”** means (a) any substance included within the definitions of “hazardous substances,” “hazardous materials,” “toxic substances,” “pollutant,” “contaminant”, “hazardous waste” or “solid waste” in any Environmental Law; (b) petroleum, including crude oil or any fraction thereof, (c) polychlorinated biphenyls; (d) asbestos and asbestos containing materials (whether friable or nonfriable); (e) lead and lead based paint or other lead containing materials (whether friable or nonfriable); and (f) naturally occurring radioactive materials.

**“Historical Period Average Prices”** means average quoted prices for relevant crude oil for the previous 12 consecutive Month periods next preceding the Month in which notice is given:

(a) if data for all the quoted items is available for more than 12 Months, but less than 24 Months then the most recent 12 Months shall be used to compute such average prices;

(b) if data for all the quoted items is available for more than 24 Months, but less than 36 Months, then the most recent 24 Months shall be used to compute such average prices;

(c) if data for all the quoted items is available for more than 36 Months, but less than 48 Months, then the most recent 36 Months shall be used to compute such average prices; and

(d) if data for all the quoted items is available for more than 48 Months, but less than 60 Months, then the most recent 48 Months shall be used to compute such average prices; and

(e) if data for all the quoted items is available for more than 60 Months, then the most recent 60 Months shall be used to compute such average prices.

**“Liability”** means any liability, obligation, debt or commitment of any kind (whether known or unknown, whether asserted or unasserted, whether absolute or contingent, whether accrued or unaccrued, whether liquidated or unliquidated, and whether due or to become due), including any liability for taxes.

**“LP”** means the linear programming model as utilized by Refiner.

**“Minimum Quality Specifications”** is defined in [Section 3.1\(b\)](#).

“**Month**” means a calendar month, extending from 12:00 A.M. Applicable Time on the first Day of such calendar month until 11:59 P.M. Applicable Time on the last Day of such calendar month.

“**Non-Defaulting Party**” is defined in Section 9.2.

“**NYMEX**” means the New York Mercantile Exchange.

“**Party**” and “**Parties**” are defined in the preamble.

“**Person**” or “**Persons**” means any individual, corporation, partnership, limited liability company, trust, unincorporated organization, Governmental Authority or any other form of entity.

“**Price Formula**” is defined in Section 4.1.

“**Prudent Industry Practices**” means those practices, methods, standards of safety and acts, which are as a minimum in accordance with standards generally observed and applicable to the crude pipeline and refining industry in the United States which a reasonable and prudent Person would follow in connection with refining facilities similar to the Refinery to accomplish the desired result lawfully, reliably and safely.

“**Purchase Price**” means the price determined using the Price Formula.

“**Refiner**” is defined in the preamble.

“**Refiner Indemnified Party**” means Refiner, its Affiliates and their respective officers, directors, employees and agents.

“**Refinery**” is defined in the Recitals.

“**Refinery Modifications**” means the design, engineering, construction, startup and operation of modifications to the Refinery such that the Refinery is capable of processing not less than 5000 Barrels per Day of Crude Oil.

“**Refinery Modification Completion**” means that the Refinery Modifications have been successfully completed and are operational, in the sole judgment of Refiner.

“**Supplier**” is defined in the preamble.

“**Supplier Indemnified Party**” means Supplier, its Affiliates and their respective officers, directors, employees and agents.

“**Term**” is defined in Section 5.1.

“**WTI, Cushing**” means the New York Mercantile Exchange (NYMEX) calendar month average light sweet crude oil front month contract price for the month of delivery.

**SCHEDULE 2.1**

**QUALITY RANGES OF CRUDE OIL**

Property	Test Methodology	Units	Typical Range	MIN/MAX
API Density	ASTM-D4052	° API	35	30/40
Sulfur	ASTM-D4294	wt %	0.1	0/0.1
Distillation	ASTM-D1160		See Below	
Water Content		Vol. %	1.5	0/2.0

TBP by Simulated Distillation

Percent off	Temp F
5	313
10	392
20	515
30	616
40	702
50	776
60	843
70	930
80	964
90	1034

**SCHEDULE 2.3**

**DELIVERY POINT**

Berry to supply locations of lease tankage where its Uinta Basin, Utah production will be delivered to Refiner from time to time.

**SCHEDULE 3.2**

**QUALITY TESTING PROCEDURES**

### **SCHEDULE 3.3**

#### **MEASUREMENT PROCEDURES**

All measurements shall be made from static tank gauges on a 100 percent tank table basis or by positive displacement meters or by approved custody transfer meter. All measurements and tests shall be made in accordance with the latest applicable API, ASTM or ASME-API (Petroleum PD Meter Code) published methods. Volume and gravity shall be adjusted to 15.56°C (60°F) by the use of Tables 6A and 5A of the Petroleum Measurement Tables ASTM Designation D1250 in their latest revision.

## SCHEDULE 7.8

### CONTINUING GUARANTY

WHEREAS, Holly Refining & Marketing Company - Wood Cross (hereinafter referred to as "CUSTOMER") has requested Berry Petroleum Company, and any of its Subsidiaries, Affiliates or Divisions (hereinafter collectively referred to as "BERRY"), to supply and/or exchange or to continue to supply and/or exchange crude oil and petroleum products and any related charges and services (hereinafter referred to as "PRODUCT") to CUSTOMER; and

WHEREAS, Berry has requested this Guaranty from HOLLY CORPORATION (here-in-after referred to as "GUARANTOR"), parent company of CUSTOMER:

NOW, THEREFORE, in order to induce BERRY to continue to extend credit to CUSTOMER and in consideration of BERRY's entering into that certain Crude Oil Supply Agreement dated February 27, 2007 ("CONTRACT") with CUSTOMER and of the first PRODUCT delivered by Berry to CUSTOMER on credit after the execution of the CONTRACT which GUARANTOR acknowledges is sufficient consideration for the issuance of this Guaranty by GUARANTOR, GUARANTOR hereby guarantees to BERRY the full and prompt payment to BERRY of all Indebtedness which CUSTOMER hereafter incurs for PRODUCT which BERRY sells and/or exchanges to CUSTOMER or otherwise for CUSTOMER's performance of the CONTRACT ("Indebtedness") so long as the CONTRACT is in full force and effect and until CUSTOMER has fully performed the CONTRACT.

Notwithstanding any other provision of this GUARANTY, (a) GUARANTOR'S liability under this GUARANTY shall not exceed the aggregate amount of \$25,000,000 and (b) GUARANTOR'S liability under this GUARANTY shall terminate automatically on July 1, 2013, but such termination shall not relieve GUARANTOR from liability for any Indebtedness covered by this GUARANTY and incurred by CUSTOMER prior to July 1, 2013.

In the event of nonpayment by CUSTOMER of any indebtedness covered by this Guaranty, BERRY may enforce its rights or remedies against either CUSTOMER or GUARANTOR in such manner as it may in its sole discretion determine, and may proceed upon the GUARANTY herein contained without first proceeding either against CUSTOMER or to enforce any lien rights and further may exercise its rights and remedies simultaneously against both CUSTOMER and GUARANTOR. GUARANTOR specifically acknowledges that the obligations under this GUARANTY shall remain in full force and effect notwithstanding any bankruptcy or reorganization case or proceeding concerning CUSTOMER.

This GUARANTY shall be governed by and construed in accordance with the laws of the State of Utah and, to the extent controlling, laws of the United States of America.

GUARANTOR authorizes BERRY, either before or after revocation hereof, without notice to or demand on GUARANTOR and without affecting GUARANTOR's liability hereunder, from time to time to: (a) alter, compromise, renew, extend, accelerate or otherwise change the time for payment of, or otherwise change the terms of the CONTRACT or any part thereof, including increase or decrease of the rate of interest thereon; and (b) apply payments received by BERRY from CUSTOMER to any Indebtedness of CUSTOMER to BERRY, in such order as BERRY

shall determine in its sole discretion, whether or not any such Indebtedness is covered by this GUARANTY, and GUARANTOR hereby waives any provision of law regarding application of payments which specifies otherwise. BERRY may with notice assign this GUARANTY in whole or in part.

GUARANTOR has established adequate means of obtaining from CUSTOMER on a continuing basis financial and other information pertaining to CUSTOMER's financial condition. GUARANTOR agrees to keep adequately informed from such means of any facts, events or circumstances that might in any way affect GUARANTOR's risks hereunder, and GUARANTOR further agrees that BERRY shall have no obligation to disclose to GUARANTOR any information or material about CUSTOMER that is acquired by BERRY in any manner.

All reasonable and actually incurred payments, advances, charges, costs and expenses, including reasonable attorney fees, made or incurred by BERRY in the enforcement of this GUARANTY or in the collection of any of the Indebtedness of CUSTOMER to BERRY shall be paid by GUARANTOR promptly upon demand, and, if not paid within 10 days of receiving notice, together with interest at a rate per annum equal to the interest rate being charged by BERRY's primary lender to BERRY under outstanding credit facilities.

This GUARANTY represents the final agreement between GUARANTOR and BERRY may not be contradicted by evidence of prior, contemporaneous or subsequent oral agreements of the parties. There are no unwritten oral agreements between GUARANTOR and BERRY.

HOLLY CORPORATION

Date: \_\_\_\_\_

By: \_\_\_\_\_

**SCHEDULE 11.1A**

**CONTINUING GUARANTY (FOR EXTENSION PERIOD)**

WHEREAS, Holly Refining & Marketing Company - Wood Cross (hereinafter referred to as "CUSTOMER") has requested Berry Petroleum Company, and any of its Subsidiaries, Affiliates or Divisions (hereinafter collectively referred to as "BERRY"), to supply and/or exchange or to continue to supply and/or exchange crude oil and petroleum products and any related charges and services (hereinafter referred to as "PRODUCT") to CUSTOMER; and

WHEREAS, Berry has requested this Guaranty from HOLLY CORPORATION (here-in-after referred to as "GUARANTOR"), parent company of CUSTOMER:

NOW, THEREFORE, in order to induce BERRY to continue to extend credit to CUSTOMER and in consideration of BERRY's entering into an extension of the Term under that certain Crude Oil Supply Agreement dated February 27, 2007 ("CONTRACT") with CUSTOMER and of the first PRODUCT delivered by Berry to CUSTOMER on credit after the extension of the Term of the CONTRACT which GUARANTOR acknowledges is sufficient consideration for the issuance of this Guaranty by GUARANTOR, GUARANTOR hereby guarantees to BERRY the full and prompt payment to BERRY of all Indebtedness which CUSTOMER hereafter incurs for PRODUCT which BERRY sells and/or exchanges to CUSTOMER or otherwise for CUSTOMER's performance of the CONTRACT during the extension of the Term ("Indebtedness") so long as the CONTRACT is in full force and effect and until CUSTOMER has fully performed the CONTRACT.

Notwithstanding any other provision of this GUARANTY, (a) GUARANTOR'S liability under this GUARANTY shall not exceed the aggregate amount of \$25,000,000 and (b) GUARANTOR'S liability under this GUARANTY shall terminate automatically on [insert expiration date of term extension], but such termination shall not relieve GUARANTOR from liability for any Indebtedness covered by this GUARANTY and incurred by CUSTOMER prior to [repeat date].

In the event of nonpayment by CUSTOMER of any indebtedness covered by this Guaranty, BERRY may enforce its rights or remedies against either CUSTOMER or GUARANTOR in such manner as it may in its sole discretion determine, and may proceed upon the GUARANTY herein contained without first proceeding either against CUSTOMER or to enforce any lien rights and further may exercise its rights and remedies simultaneously against both CUSTOMER and GUARANTOR. GUARANTOR specifically acknowledges that the obligations under this GUARANTY shall remain in full force and effect notwithstanding any bankruptcy or reorganization case or proceeding concerning CUSTOMER.

This GUARANTY shall be governed by and construed in accordance with the laws of the State of Utah and, to the extent controlling, laws of the United States of America.

GUARANTOR authorizes BERRY, either before or after revocation hereof, without notice to or demand on GUARANTOR and without affecting GUARANTOR's liability hereunder, from time to time to alter, compromise, renew, extend, accelerate or otherwise change the time for payment of, or otherwise change the terms of the CONTRACT or any part thereof, including increase or decrease of the rate of interest thereon. BERRY may with notice assign this GUARANTY in whole or in part only connection with an assignment permitted pursuant to the CONTRACT.

GUARANTOR has established adequate means of obtaining from CUSTOMER on a continuing basis financial and other information pertaining to CUSTOMER's financial condition. GUARANTOR agrees to keep adequately informed from such means of any facts, events or circumstances that might in any way affect GUARANTOR's risks hereunder, and GUARANTOR further agrees that BERRY shall have no obligation to disclose to GUARANTOR any information or material about CUSTOMER that is acquired by BERRY in any manner.

All reasonable and actually incurred payments, advances, charges, costs and expenses, including reasonable attorney fees, made or incurred by BERRY in the enforcement of this GUARANTY or in the collection of any of the Indebtedness of CUSTOMER to BERRY shall be paid by GUARANTOR promptly upon demand, and, if not paid within 10 days of receiving notice, together with interest at a rate per annum equal to the interest rate being charged by BERRY's primary lender to BERRY under outstanding credit facilities.

This GUARANTY represents the final agreement between GUARANTOR and BERRY may not be contradicted by evidence of prior, contemporaneous or subsequent oral agreements of the parties. There are no unwritten oral agreements between GUARANTOR and BERRY.

HOLLY CORPORATION

Date: \_\_\_\_\_

By: \_\_\_\_\_



**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 28, 2007 relating to the financial statements, management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Los Angeles, California  
February 28, 2007

**DeGolyer and MacNaughton**

5001 Spring Valley Road  
Suite 800 East  
Dallas, Texas 75244

February 28, 2007

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, 2006, (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, 2006 on Certain Properties owned by Berry Petroleum Company," "Appraisal Report as of December 31, 2005 on Certain Properties owned by Berry Petroleum Company," and "Appraisal Report as of December 31, 2004 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

**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 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 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 28, 2007

**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

Executive Vice President and Chief Financial Officer

February 28, 2007

**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, 2006 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

President, Chief Executive Officer and Director

February 28, 2007

**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, 2006 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

Executive Vice President and Chief Financial Officer

February 28, 2007