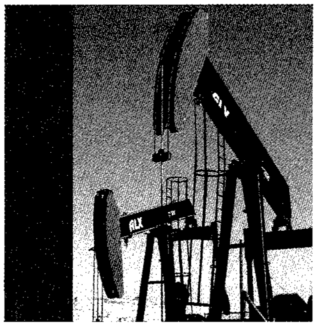
Berry Petroleum Company

2008 ANNUAL REPORT



CORPORATE PROFILE

Berry Petroleum Company is an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. Publicly traded since 1987, Berry traces its roots in California heavy oil production back to 1909. Currently, Berry's principal reserves and producing properties are in California, Utah (Uinta basin), Colorado (Piceance) and East Texas. At December 31, 2008, the Company reported proved reserves of 246 million barrels of oil equivalent (BOE) distributed 45% in California, 35% in the Rocky Mountain region and 20% in East Texas with a reserve mix of 51% crude oil and 49% natural gas. In the first quarter of 2009, the Company entered into an agreement to sell its Denver-Julesburg assets that are included in the preceding statistics. After the DJ asset sale closes, proved reserves will total 225 million BOE. The regional distribution will be 49% in California, 29% in the Rocky Mountain region and 22% in East Texas with a reserve mix of 51% crude oil and 49% natural gas.

CERTIFICATION STATEMENTS

The New York Stock Exchange's Rule 303A.12(a) requires chief executive officers of listed corporations to certify that they are not aware of any violations by their company of the Exchange's corporate governance listing standards. This annual certification by the chief executive officer of Berry Petroleum Company has been filed with the New York Stock Exchange. In addition, Berry Petroleum Company has also filed, as exhibits to its most recently filed Form 10-K, the Securities and Exchange Commission certifications required for the chief executive officer and chief financial officer under section 302 of the Sarbanes-Oxley Act.

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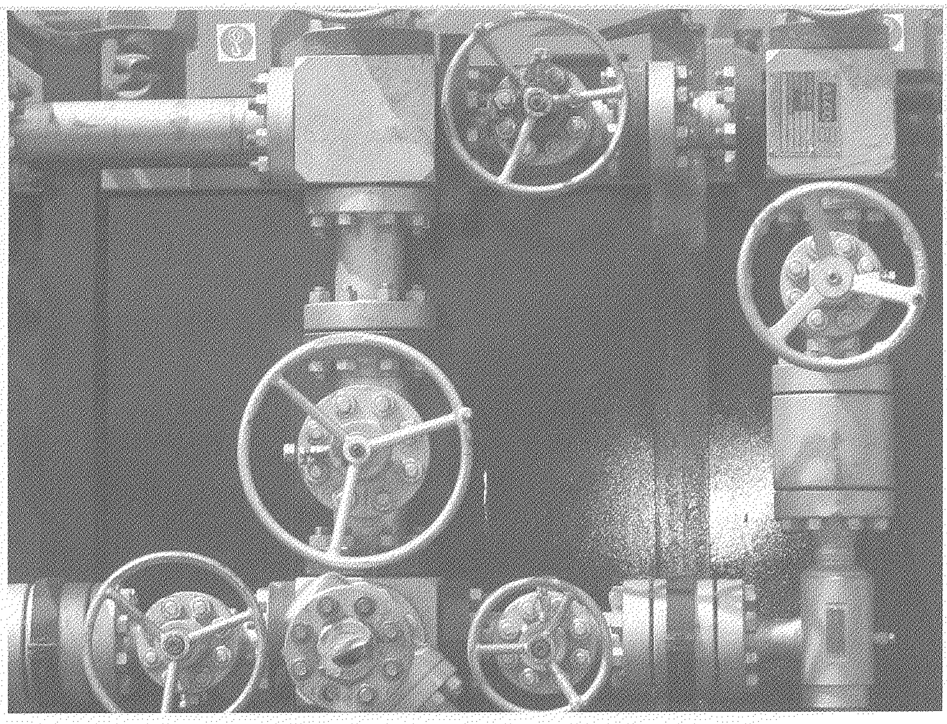
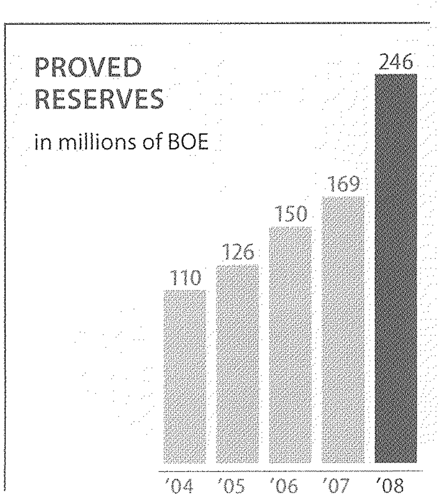


Letter to *Our* Shareholders

2008 was an extraordinary year for oil and gas producers, including Berry Petroleum Company. The first half of the year saw a rapid increase in commodity prices with crude oil rising to over $140 per barrel and natural gas increasing to over $13 per thousand cubic feet. In the second half of 2008, we saw prices fall faster than they had increased in the first half with both oil and gas prices dropping by 65%.

Through this tumultuous period Berry achieved significant growth in production, cash flow and reserves. Production averaged 32,000 barrels of oil equivalent per day (BOE/D) with increases from developments in our diatomite and Poso Creek assets in California and our Piceance assets in Colorado, as well as our East Texas acquisition. Operating cash flow for 2008 increased by 71% to $410 million due to the Company's 19% production growth and was supported by realized commodity prices which averaged $59.81 per BOE after hedging.



Proved reserves at year-end 2008 increased 45% to 246 million BOE and we replaced over seven times the 11.7 million BOE produced last year. The "all-in" finding and development (F&D) cost, including the East Texas acquisition, was $12.30 per BOE, one of the best among independents.

Despite an overall strong performance in 2008, we also experienced challenges. In addition to the pronounced declines in commodity prices, the United States grappled with economic turbulence in the banking and financial services industries coincident with the Company's acquisition of assets in East Texas. In late December 2008, a local refinery owned by Flying J, to which we had sold our heavy oil production since 2006, declared bankruptcy that forced a shut-in of our California production.

While these events impacted our business and stock price, our focus for the last six months has been to address those issues that we can proactively influence in order to maintain the Company on a firm financial and operational footing.

We point to seven initiatives we have undertaken to reinforce confidence in Berry Petroleum Company and to prepare us for the years to come.

- **Reduced Costs**
  We reduced our development activity sharply late last year as commodity prices declined. We also focused proactively on cost reductions because of the impact that the higher 2008 operating cost structure could have on year-end reserves calculations. For 2009 we are targeting a 20% to 25% reduction in operating, capital and general and administrative costs compared to 2008.

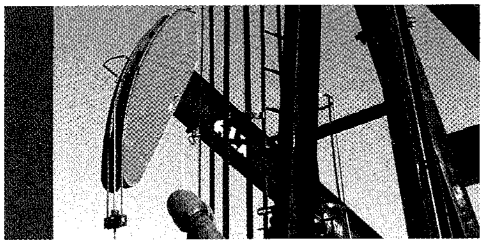
FINANCIAL HIGHLIGHTS

	YEAR ENDED DECEMBER 31,				
	2008	2007	2006	2005	2004
FINANCIAL DATA (in millions, except share amounts)					
Operating Revenues (sales of oil and gas)	$ 698	$ 467	$ 430	$ 350	$ 227
Net Income	$ 134	$ 130	$ 108	$ 112	$ 69
Per Share - Diluted	$ 2.94	$ 2.89	$ 2.41	$ 2.50	$ 1.54
Net Cash Flows From Operations	$ 410	$ 239	$ 258	$ 188	$ 125
Capital Expenditures (including acquisitions)	$ 1,066	$ 341	$ 544	$ 243	$ 75
Dividends Per Share	$ .30	$ .30	$ .30	$ .30	$ .26
Average Common Shares Outstanding - Diluted	45.4	44.9	44.8	45.0	44.9
CAPITALIZATION (in millions)					
Long-Term Debt	$ 1,132	$ 445	$ 390	$ 75	$ 28
Shareholders' Equity (successful efforts)	$ 828	$ 460	$ 428	$ 334	$ 263
NET ANNUAL PRODUCTION VOLUME (in millions, except %)					
Oil Barrels	7.4	7.2	7.2	7.1	7.0
Natural Gas Mcf	25.6	15.7	12.5	7.9	2.8
Total BOE	11.7	9.8	9.3	8.4	7.5
% Production Growth (over prior year)	19%	6%	10%	12%	24%
% Of Production Which Is Natural Gas	36%	27%	22%	16%	6%
REALIZED AVERAGE SALES PRICE (with hedging)					
Oil (per barrel)	$ 70.01	$ 53.24	$ 50.55	$ 40.85	$ 28.57
Natural Gas (per MMBTU)	$ 7.01	$ 5.27	$ 5.57	$ 7.63	$ 5.49
BOE (per barrel of oil equivalent)	$ 59.81	$ 47.50	$ 46.67	$ 41.62	$ 30.32
GROSS PRODUCTIVE WELLS DRILLED					
Oil	248	230	258	113	121
Natural Gas	198	186	281	113	7
Total	446	416	539	226	128
RESERVE ADDITIONS					
Reserve Replacement Rate[1]	756%	293%	359%	296%	99%
Three-year Average Reserve Replacement Rate	489%	316%	260%	212%	137%
FD&A[2] Cost Per BOE	$ 12.30	$ 10.07	$ 16.78	$ 9.34	$ 8.02
Three-year Average FD&A Cost Per BOE	$ 12.75	$ 12.23	$ 12.77	$ 8.29	$ 7.39
PROVED RESERVES (in millions, except %)					
Oil Bbl	125	117	113	104	106
Natural Gas Mcf	724	315	226	135	26
Total BOE	246	169	150	126	110
% Natural Gas	49%	31%	25%	18%	4%
% Developed	55%	61%	68%	72%	74%
Reserve Life (years, using annualized Q4 production rate)	19	17	15	15	14

Abbreviations in above table: Bbl – barrel; BOE – barrel of oil equivalent (with gas at 6:1 ratio); Mcf – thousand cubic feet; MMBTU – million British Thermal Units; F&D – finding and development; FD&A; finding, development and acquisition

[1] The reserve replacement rate is calculated by dividing net reserve additions for the year by total production for the year

[2] Acquisition, exploration and development costs divided by reserve revisions, improved recoveries, extensions, discoveries and purchase of reserves in place



- **Secured Refining Contracts**
We successfully returned our California operations to full production in early 2009 and marketed our heavy California crude in January, February and March under short-term agreements with a variety of refiners in California. During this time, the price difference between the light oil benchmark (WTI) and California heavy oil decreased to less than $6 per barrel from $14 per barrel. We expect in the near-term to enter into multi-month contracts with several refineries for our California heavy crude sales which we expect will pay a premium to this heavy oil differential.

- **Increased Oil Hedges**
We increased hedging levels to 90% of our crude production for 2009 such that if WTI crude prices average $40 per barrel, the Company will realize approximately $65.50 per BOE, less differentials. These hedging levels, combined with our crude contracts, make the recent decline in the heavy oil differential even more important to our operating cash flow projections which now approach $200 million for 2009.

- **Amended Credit Facility**
We quickly took steps to amend our credit facility to ensure that we would remain in compliance with the covenants under the terms of that facility as a result of the $38 million write-off of accounts receivable attributable to the Flying J bankruptcy. This action resulted in a modification of the covenants which improves our financial flexibility to raise capital under the terms of our bank facility including, but not limited to, second lien financing, unsecured debt and other junior debt.

- **Hedged Interest Rates**
We minimized the effects of increases in interest rates on the rate we pay on our bank debt by locking in LIBOR rates through 2012 in the 2% range using interest rate hedges and swaps.

- **Sold DJ Asset**
We agreed in the first quarter of 2009 to sell our Denver-Julesburg natural gas assets in Northeastern Colorado for $154 million and upon closing will use the proceeds to pay down bank debt. This move alone will reduce outstanding debt by 12%. We plan to continue to reduce debt in 2009 through payments from operational cash flow.

- **Balanced Capital Program**
We, with the oversight of the Board, also developed a 2009 capital program that invests in our higher return projects, balances expenditures to be within operating cash flow and produces a projected average of over 30,000 BOE/D in 2009.

Commodity-based businesses are cyclical by their very nature. Oil and gas prices are at the bottom of the current cycle primarily due to a reduction in demand caused by the deep recession seen around the globe. During such times, we believe the prudent, near-term strategy for Berry Petroleum is to focus on cost reductions, improve our balance sheet, maximize the value of our oil and gas production through marketing and hedging and seek opportunities to optimize our portfolio of assets. We are pleased with the progress being made on all these fronts.

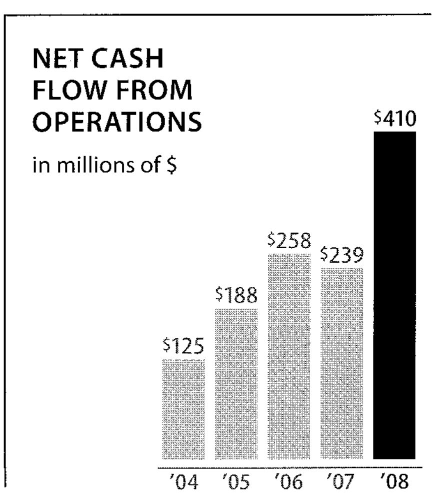
We welcome David Wolf in his role as Executive Vice President and Chief Financial Officer. He brings an intimate knowledge of the credit and capital markets to Berry which is vital in the current environment.

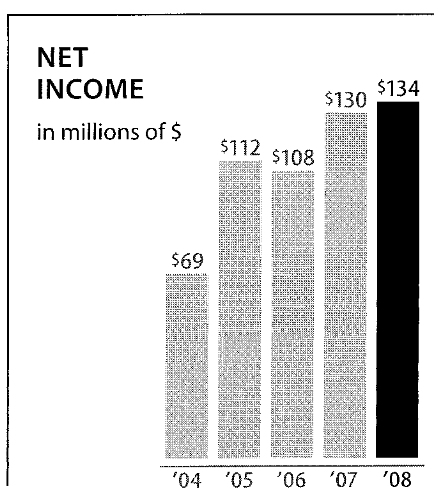
Financial Highlights

The Company earned net income of $134 million or $2.94 per share in 2008 or a 3% increase from last year's net income of $130 million or $2.89 per share.

The full-year results for 2008 include a $12 million loss from the fourth quarter due to a $38 million write-off of receivables from the bankruptcy of Flying J. We also wrote-off certain rig related charges and dry hole expenses in the fourth quarter. For the full-year 2008 these write-offs reduced our net income by approximately $25 million or $0.56 per share. The Flying J bankruptcy accounted for about 85% of this reduction.

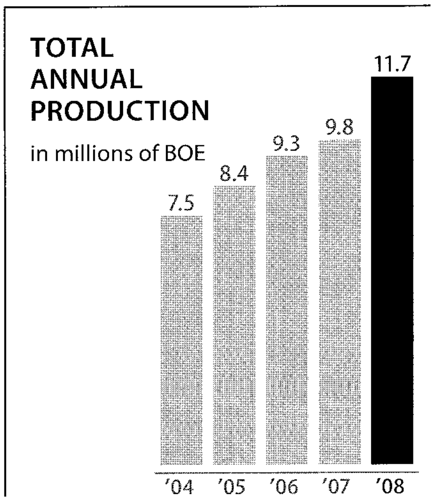
Full-year 2008 oil and gas revenues were $698 million with oil revenues contributing $519 million and gas revenues $179 million. Total operating costs for 2008 averaged $38.44 per BOE and our oil and gas operating costs were $17.10 per BOE.

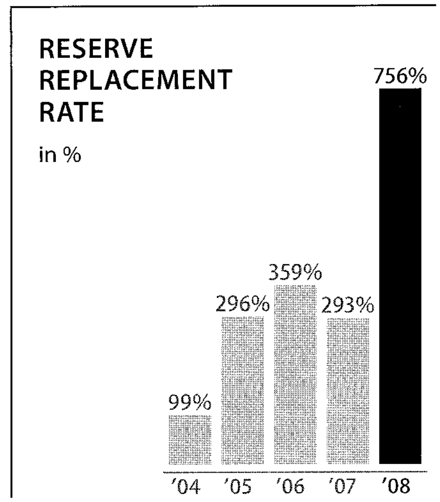




Operational Highlights

Year-end proved reserves totaled 246 million BOE. These reserve additions were driven by $398 million of development capital and $668 million of acquisition capital. The 88 million BOE of proved reserve additions replaced 756% of the Company's 2008 production with 43% of the total being replaced from our development capital for an organic replacement rate of 392%. The quality of our reserves was highlighted by the fact that we had no write-downs from ceiling tests at year-end 2008. The reserve-to-production ratio increased to 19 years.





Diatomite production increased 86% over 2007 to over 1,800 BOE/D, and diatomite proved reserves increased by 160% to over 30 million BOE as a result of drilling 85 development wells, along with additional production history demonstrating ultimate recoveries. Poso Creek production increased 59% to 3,100 BOE/D from a 28-well program and we were able to hold our S. Midway proved reserves flat after production, offsetting a low base decline with improved recovery from deeper zones and the flanks of the field.

Our Piceance production increased 103% to 20,750 Mcf/D and proved reserves increased 80% to 42 million BOE from drilling 72 gross wells and from the active development of the offset operators on our property.

The Company made a significant acquisition of two properties in Limestone and Harrison Counties of East Texas for $668 million, which closed in July 2008, establishing a new core area for Berry.

The assets include over 100 producing natural gas wells on 4,500 acres, and we have identified over 100 additional drilling locations targeting multi-zone stacked-pay opportunities. This is an excellent entry point into a price-favored basin with strong cash margins and excellent potential to grow production with upside exposure to a prolific shale play. The East Texas acquisition added 50 million BOE of proved reserves to our year-end total at an average cost of $13.36 per BOE.

2009 Plans

Our capital budget for 2009 is $100 million and because we operate substantially all of our production, we can manage our spending within cash flows, which we expect to range between $170 million to $200 million. We will invest in our highest return projects and keep operating costs in line with commodity prices as we weather this challenging environment.

Our capital spending in 2009 will be directed largely at our N. Midway diatomite oil development and our East Texas natural gas development. In total the budget division is $51 million in California, $35 million in East Texas and $14 million in the Rockies.

We expect California production to grow, with the diatomite production growth offsetting other heavy oil natural declines. Without significant capital investment in the Piceance we expect production declines in our Rockies natural gas assets.

East Texas production will remain flat with a one rig drilling program. We have completed vertical Haynesville tests in 2008 that demonstrated the productivity of the shale on our properties. We expect to drill our first horizontal Haynesville well by midyear. We are also actively evaluating a Bossier shale horizontal well at our Freestone property.

Summary

Your management and Board are being proactive to ensure that Berry remains well situated to return to growth as the economy and commodity prices begin to recover. We continue to look for reductions in expenses and are striving to realize operating margins better than $25 per BOE as we did in 2004 and 2005 when crude prices were also around $40 to $50 per barrel.

We believe our near-term strategy combined with long-lived assets, a tightening California differential, a solid hedging program and a plan to continue to reduce debt will allow us to negotiate through 2009 successfully and capitalize on the Company's fundamental strengths.

Sincerely,

Martin H. Young Jr.
Martin H. Young Jr.
Chairman of the Board

Robert F. Heinemann
Robert F. Heinemann
President and CEO

March 18, 2009

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

FORM 10-K

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2008**
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)

1999 Broadway
Denver, Colorado 80202
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code:
(303) 999- 4400

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, $0.01 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 ☐ NO ☒
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 ☐ NO ☒
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 ☒ NO ☐
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. ☐
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer☒ Accelerated filer☐ Non-accelerated filer☐ Smaller reporting company☐
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES ☐ NO ☒
As of June 30, 2008, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $2,173,457,341. As of February 2, 2009, the registrant had 42,782,521 shares of Class A Common Stock outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on February 2, 2009 all of which are held by an affiliate of the registrant.

DOCUMENTS INCORPORATED BY REFERENCE

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

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Forward Looking Statements

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

PART I

Item 1. Business

General. We are an independent energy company engaged in the production, development, acquisition, exploitation of and exploration for, crude oil and natural gas. While we were incorporated in Delaware in 1985 and have been a publicly traded company since 1987, we can trace our roots in California oil production back to 1909. In 2003, we purchased and began operating properties in the Rocky Mountains. In 2008, we purchased and began operating properties in East Texas (E. Texas). Also in 2008, we relocated our corporate headquarters to Denver, Colorado and we have regional offices in Bakersfield, California and Plano, Texas. Information contained in this report on Form 10-K reflects our business during the year ended December 31, 2008 unless noted otherwise.

Our website, located at http://www.bry.com, can be used to access recent news releases and Securities and Exchange Commission (SEC) filings, crude oil price postings, hedging summaries, our Annual Report, Proxy Statement, Board committee charters, Corporate Governance Guidelines, code of business conduct and ethics, the code of ethics for senior financial officers, and other items of interest. Information on our website is not incorporated into this report. 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 the value of our business 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 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. We also have large potential hydrocarbon resources in place in the San Joaquin Valley, California (diatomite); Piceance, Colorado; Uinta, Utah (Lake Canyon); and Cotton Valley Trend in E. Texas. We have a proven track record of developing reserves and establishing new businesses in the Rocky Mountain and E. Texas regions.

Investing our capital in a disciplined manner and maintaining a strong financial position. We focus on utilizing our available capital on projects where we are likely to have success in increasing production and/or reserves at attractive returns. We believe that maintaining a strong financial position will allow us to capitalize on investment opportunities in all commodity cycles. Our capital programs are developed to be fully funded through internally generated cash flows while our acquisitions have been primarily funded through debt. We hedge a significant portion of our production and utilize long-term sales contracts whenever possible to maintain a strong financial position and provide the cash flow necessary for the development of our assets.

Acquiring additional assets with significant growth potential. We will continue to evaluate oil and gas properties with proved reserves, probable reserves and/or acreage positions that we believe contain substantial hydrocarbons which can be developed at reasonable costs. In July 2008 we completed the acquisition of natural gas producing properties in E. Texas for approximately $650 million. We will continue to review asset acquisitions that meet our economic criteria with a primary focus on large repeatable development potential in these regions.

Accumulating significant acreage positions near our producing operations. We have been successful in adding significant acreage positions in our producing areas. This strategy allows us to leverage our operating and technical expertise within the area and build on established core operations.

Business strengths.

Balanced high quality asset portfolio with a long reserve life. Since 2002, we have grown our asset base and diversified our California heavy oil through a number of acquisitions in the Rocky Mountain and East Texas regions that have significant growth potential. Our diverse asset base provides us with the flexibility to reallocate capital among our assets depending on fluctuations in natural gas and oil prices as well as area economics. Our production based asset teams are focused around S.Midway-Sunset, Southern California and DJ assets. Our resource based asset teams are focused around diatomite, Piceance, Uinta and our newly acquired E. Texas assets. Our base of legacy California assets provides us with a steady stream of cash flow to fund our significant drilling inventory and the appraisal of our prospects. Our wells are generally characterized by long production lives and predictable performance.

Low-risk multi-year drilling inventory in established resource plays. Most of our drilling locations are located in proven resource plays that possess low geologic risk leading to predictable drilling results. Our historical drilling success rate for the three years ended December 31, 2008 has averaged 98%.

Experienced management and operational teams. Our core team of technical staff and operating managers have broad industry experience, including experience in heavy oil thermal recovery operations and 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.

Track record of efficient proved reserve and production growth. For the three years ended December 31, 2008, our proved reserves and production increased at an annualized compounded rate of 25% and 12%, respectively. We apply our operational expertise to improve the efficiency and profitability of our drilling projects. For example, in the Piceance we have decreased our well drilling time from 40 days in 2006 to under 10 days in 2008, while at the same time increasing our initial production rates from 1,250 Mcfe/d to 1,350 Mcfe/d. We believe we can continue to deliver strong and efficient growth through the drill bit by exploiting our drilling inventory. We also plan to complement this drill bit growth through selective and focused acquisitions.

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 more effectively control operating costs, timing of development activities and technological enhancements, marketing of production, and 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 of our capital budget. We finance our drilling budget primarily through our internally generated operating cash flows.

Long Lived Proved Reserves. 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, 2008) of approximately 19 years as compared to 16.5 years at year end 2007. Our estimated proved reserves as of December 31, 2008 were 246 million BOE, of which 45% are heavy crude oil, 6% light crude oil and 49% natural gas. We have a geographically diverse asset base with 45% of our proved reserves located in California, 35% in the Rocky Mountains and 20% in East Texas. Of our proved reserves 55% were proved developed, while proved undeveloped reserves make up 45% of our proved total. The projected future capital to develop these proved undeveloped reserves is $950 million at an estimated cost of approximately $8.55 per BOE. Approximately 61% of the capital to develop these reserves is expected to be expended in the next five years.

We have organized our operations into seven asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including diatomite (N. Midway), Southern California including Poso Creek and Placerita (S. Cal), Piceance, Uinta, DJ and E. Texas. The following table sets forth the estimated quantities of proved reserves and production attributable to our asset teams as of December 31, 2008.

State	Name	Type	Average Daily Production (BOE/D)	% of Daily Production	Proved Reserves (BOE) in millions	% of Proved Reserves	Oil & Gas Revenues before hedging (in millions)	% of Oil & Gas Revenues before hedging
CA	S. Midway	Heavy oil	8,798	28 %	52.7	22 %	$ 278	34 %
UT	Uinta	Light oil/Natural gas	6,142	19	23.3	9	136	17
CA	S. Cal	Heavy oil	5,117	16	17.7	7	173	21
CO	Piceance	Natural gas	3,511	11	41.8	17	53	6
CO	DJ	Natural gas	3,295	10	21.5	9	49	6
CA	N. Midway	Heavy oil	2,714	9	38.9	16	91	11
TX	E. Texas	Natural gas	2,384	7	50.0	20	40	5
	Other	Heavy oil/Natural gas	7	-	-	-	-	-
Totals			31,968	*100* %	245.9	*100* %	$ 820	*100* %

We continue to engage DeGolyer and MacNaughton (D&M) to appraise the extent and value of our proved oil and gas reserves and the future net revenues to be derived from our properties for the year ended December 31, 2008. D&M is an independent oil and gas consulting firm. 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, 2008. 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 Operations.

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

In the Rocky Mountains, crude oil produced from the Uinta properties is transported by truck. Natural gas produced from the Uinta, DJ and Piceance properties is transported to one of several main pipelines. We have seven firm transportation contracts on four different pipelines to provide transport for our Rocky Mountain natural gas production. See table on page 7. In E. Texas, natural gas produced from the Darco and Oakes properties is transported intra-state on the Enbridge system to various market points.

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

Economy. Global and regional demand for crude oil and natural gas declined in the latter part of 2008 as part of the overall economic recession. Oil is a globally priced commodity and is priced according to the supply and demand of crude oil and its products. The range of NYMEX light sweet crude prices for 2008, based upon settlements, was a low of $33.87 and a high of $145.29.

	2008	2007	2006
Average NYMEX settlement price for WTI	$ 99.75	$ 72.41	$ 66.25
Average posted price for:			
Utah 40 degree API black wax (light) crude oil	84.99	59.28	56.34
California 13 degree API heavy crude oil	86.51	61.64	54.38
Average crude price differential between WTI and:			
Utah light 40 degree API black wax (light) crude oil	14.76	13.13	9.91
California 13 degree API heavy crude oil	13.24	10.77	11.87

The above posting prices and differentials do not necessarily reflect the amounts paid or received by us due to the contracts discussed below. In California the differential on December 31, 2008 was $14.05 and ranged from a low of $12.31 to a high of $14.96 per barrel during the year. On December 31, 2008 the differential was $16.25 and ranged from a low of $13.75 to a high of $16.25 per barrel during the year.

Oil Contracts. We market our crude oil production to competing buyers which may be independent or major oil refiners or third party marketers.

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 crude oil sales contract with Big West of California (BWOC), an independent refiner, for substantially all of our California production for deliveries beginning February 1, 2006 and ending January 31, 2010. After the initial term of the contract, we have a one-year renewal at our option. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of 1) the WTI NYMEX crude oil price less a fixed differential approximating $8.10, or 2) heavy oil field postings plus a premium of approximately $1.35.

In December 2008, Flying J, Inc., and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's production. We have entered into various short-term agreements with other companies to sell our California oil production. Pricing and volumes under these agreements vary with prices ranging from just above the posted price for San Joaquin heavy oil to the posted price less a discount. Beginning January 2009, our California crude oil daily production was, on average, near levels achieved prior to BWOC's Chapter 11 filing. BWOC is evaluating several options, including a sale of the Bakersfield, California refinery. We recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of the $38.5 million due from BWOC, $12.4 million represents December crude oil sales by the Company and represents an administrative claim under the bankruptcy proceedings and $26.1 million represents November crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract for any amounts received by us under our short-term contracts which are less than what we would have otherwise received from BWOC had they been able to accept our production. We have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that our claim is not fully collectible from BWOC. While we believe that we may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected nor as to whether BWOC will assume or reject our contract.

Utah - On February 27, 2007, we entered into a multi-staged crude oil sales contract through June 30, 2013 with a refiner for the purchase of our Uinta light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D on July 1, 2007. After partial completion of its refinery expansion in Salt Lake City in March 2008, the refiner increased its total purchase volumes to 5,000 Bbl/D. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI, and ranges between $10 and $15 at WTI prices between $40 and $60. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company's 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company's crude oil.

Natural Gas Marketing. We market our produced natural gas from Colorado, Utah and Texas. Generally, natural gas is sold at monthly index related prices plus an adjustment for transportation. Certain volumes are sold at a daily spot related price. Approximately two-thirds of the pricing of our Rocky Mountain natural gas production is tied to the Panhandle Eastern Pipeline (PEPL) index and the remaining volume to the Colorado Interstate Gas (CIG) Index. E. Texas gas is priced using a formula containing the Houston Ship Channel, Texas Eastern-East Texas, and NGPL TX-OK indices.

	2008	2007	2006
Annual average closing price per MMBtu for:			
NYMEX Henry Hub (HH) prompt month natural gas contract last day	$ 9.03	$ 6.86	$ 7.23
Rocky Mountain Questar first-of-month indices (Uinta sales)	6.15	3.69	5.36
Rocky Mountain CIG first-of-month indices (DJ, WY and Piceance sales)	6.24	3.97	5.63
Mid-Continent PEPL first-of-month indices (DJ and Piceance sales)	7.08	5.99	6.02
Texas Eastern- East Texas	8.46	n/a	n/a
Average natural gas price per MMBtu differential between NYMEX HH and:			
Questar	2.88	3.17	1.87
CIG	2.79	2.89	1.60
PEPL	1.95	.87	1.21
Texas Eastern- East Texas	.57	n/a	n/a

Gas Basis Differential. Natural gas prices in the Rockies continue to be volatile due to various factors, including takeaway pipeline capacity, supply volumes, and regional demand issues. The basis differential between HH and CIG narrowed, as anticipated, upon the startup of the Rockies Express pipeline in early 2008. However, the differential started to widen again during the second quarter of 2008. We have contracted a total of 35,000 MMBtu/D on this pipeline under two separate transactions to provide firm transport for our Piceance gas production. The CIG basis differential per MMBtu, based upon first-of-month values, averaged $2.81 below HH and ranged from $0.93 to $6.62 below HH in 2008. Although related to CIG, the actual price varies. Gas from Piceance traded slightly below the CIG price while Uinta gas sold for approximately $0.15 below CIG pricing. DJ gas is priced using one of two indices. During 2008, approximately two-thirds of our volumes from our DJ natural gas properties was tied to the PEPL index for pricing and the remaining volumes to CIG pricing. Beginning in 2009, we have increased firm transportation on the Cheyenne Plains Pipeline which brings our PEPL priced gas to about three-quarters of our production. For that portion of the production with firm transportation on either the Cheyenne Plains Pipeline or the KMIGT pipeline, pricing is based upon the PEPL index which averaged approximately $1.96 below the HH index before the cost of transportation is considered. The remainder of DJ gas is sold slightly above the CIG index price. For E. Texas, the Texas Eastern - East Texas index averaged $0.58 below HH and ranged from $0.34 to $0.94 below HH in 2008.

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

Firm Transportation Summary.

Pipeline	From	To	Quantity (Avg. MMBtu/D)	Term	December 31, 2008 demand charge per MMBtu	Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$ 0.6407	$ 12,160
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 2/2018	1.1153(1)	93,288
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	1/2008 to 1/2018	1.07694(1)	36,032
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,500	9/2003 to 4/2012	0.174	529
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,859	9/2003 to 9/2012	0.174	681
Questar Pipeline	Brundage Canyon, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.257	6,488
KMIGT	Yuma County, CO	Grant, KS	2,500	1/2005 to 10/2013	0.227	1,001
Cheyenne Plains Gas Pipeline	Yuma County, CO	Kiowa County, KS	12,000(2)	1/2007 to 12/2016	0.34	14,892
Total			71,859			$ 165,071

(1) Base cost per MMBtu is a weighted average cost.

(2) Volume increase to 15,000 MMBtu/D starting January 1, 2009 for remaining life of contract.

Berry has signed a binding precedent agreement with El Paso Corporation for an average of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. While it is not certain that this new line will be constructed, the expectation is that the project will proceed and be in service in 2011. As part of this agreement and in order to access the Ruby pipeline, we also secured firm transportation from Piceance to Opal.

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

Hedging. See Item 7A Quantitative and Qualitative Disclosures about Market Risk and Note 18 to the financial statements.

Concentration of Credit Risks. See Note 5 to the financial statements.

Steaming Operations.

Cogeneration Steam Supply. As of December 31, 2008, approximately 45% of our proved reserves, or 109 million barrels, consisted of heavy crude oil produced from depths of less than 2,000 feet. In pursuing our goal of being a cost-efficient heavy oil producer in California, we have consistently focused on minimizing our steam cost. We believe one of the main methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on our properties. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility, are located in S. Midway. We also own a 42 MW cogeneration facility which is located in the Placerita field. Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine that would otherwise be wasted, to produce steam. This increases the efficiency of the combined process and consumes less fuel than would be required to produce the steam and electricity separately.

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

Total barrels of steam per day (BSPD) capacity as of December 31, 2008 is as follows:

Steam generation capacity of conventional boilers	87,070
Steam generation capacity of cogeneration plants	42,789
Additional steam purchased under contract with a third party	2,100
Total steam capacity	131,959

The average volume of steam injected for the years ended December 31, 2008 and 2007 was 99,908 BSPD and 87,990 BSPD, respectively.

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

In 2008, we added additional steam capacity for our development projects at N. Midway, primarily diatomite, and Poso Creek to achieve maximum production from these properties. In 2009, we plan to add one additional 5,000 BSPD generator at Poso Creek and three additional 5,000 BSPD generators on our diatomite producing properties.

We operated most of our conventional steam generators in 2008 to achieve our goal of increasing heavy oil production. Approximately 75% of the volume of natural gas purchased to generate steam and electricity is based upon California 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 25% of supply volume is purchased in the Rockies 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.

	2008	2007	2006
Average SoCal Border Monthly Index Price per MMBtu	$ 7.92	$ 6.38	$ 6.29
Average Rocky Mountain NWPL Monthly Index Price per MMBtu	6.25	3.95	5.66
Average PG&E Citygate Monthly Index Price per MMBtu	8.63	6.86	6.70

Prior to 2005, we were a net purchaser of natural gas, and thus our net income was negatively impacted when natural gas prices increased. In 2005, our production and consumption became balanced due to our eastern Colorado (DJ) gas acquisition. Subsequent to 2005, we have been a net seller of gas and benefit operationally when gas prices increase. However, our consumption of natural gas provides a form of natural hedge as our revenues received from natural gas sales are partially offset by operating cost increases in California when natural gas prices rise. The following table shows our average 2008 and estimated average 2009 amount of production in excess of consumption and hedged volumes (in average MMBtu/D):

	2008	Estimated 2009
Approximate Natural gas volumes produced in operations	69,800	75,000
Approximate Natural gas consumed:		
Cogeneration operations	26,700	26,900
Conventional boilers (1)	20,400	22,600
Total natural gas volumes consumed in operations	47,100	49,500
Less: Our estimate of approximate natural gas volumes consumed to produce electricity (2)	(20,300)	(20,500)
Total approximate natural gas volumes consumed to produce steam	26,800	29,000
Natural gas volumes hedged	18,250	20,400
Amount of natural gas volumes produced in excess of volumes consumed to produce steam and volumes hedged	24,750	25,600

(1) In 2009, we will have additional conventional capacity at Poso Creek and diatomite to increase our production from these fields.

(2) We estimate this volume based on the historical allocation of fuel costs to electricity.

Electricity.

Generation. The total annual average electrical generation of our three cogeneration facilities is approximately 83 MW, of which we consume approximately 8 MW for use in our operations. Each facility is centrally located on certain of our oil producing properties. Thus the steam generated by the facility is capable of being delivered to numerous wells that require steam for the EOR process. Our investment in our cogeneration facilities has been for the express purpose of lowering the steam costs in our heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam boilers. Cogeneration costs are allocated between electricity generation and oil and gas operations based on the conversion efficiency (of fuel to electricity and steam) of each cogeneration facility and certain direct costs to produce steam. Cogeneration costs allocated to electricity will vary based on, among other factors, the thermal efficiency of our cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of our power contracts. Although we account for cogeneration costs as described above, economically we view any profit or loss from the generation of electricity as a decrease or increase, respectively, to our total cost of producing heavy oil in California. DD&A related to our cogeneration facilities is allocated between electricity operations and oil and gas operations using a similar allocation method.

Sales Contracts. Historically, we have sold electricity produced by our cogeneration facilities, each of which is a Qualifying Facility (QF) under the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA), to two California public utilities; Southern California Edison Company (Edison) and PG&E, under long-term contracts approved by the California Public Utilities Commission (CPUC). These contracts are referred to as standard offer (SO) contracts under which we are paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) of energy plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. During most periods natural gas is the marginal fuel for California utilities, so this formula provides a hedge against our cost of gas to produce electricity and steam in our cogeneration facilities. On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes the way SRAC energy prices will be determined for existing and new Standard Offer (SO) contracts and revises the capacity prices paid under current SO1 contracts. At this time, there is no certainty as to the final formula of the SRAC Decision nor the effective date of the SRAC Decision nor whether its terms will be applied retroactively and if so, for what period.

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, as they did in the SRAC decision. 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. However, given the proceedings described above on the SRAC Decision, it is possible that some resolution of this element of retroactivity may be resolved concurrently, although there is no pending ruling. Our SO2 contract for the Placerita Unit 1 Facility is scheduled to terminate on March 31, 2009 and we are negotiating an interim contract that will become effective on April 1, 2009. The payment provisions of this interim contract are expected to be similar to the payment provisions ordered in the SRAC Decision. The Company intends to enter into new standard contracts with Edison and PG&E for all three facilities as soon as the ongoing challenges are resolved and the CPUC has approved the terms of the new standard contracts.

Based on the current pricing mechanism for our electricity under the contracts, we expect that our electricity revenues will be in the $40 million to $60 million range for 2009.

At the time of the California energy crisis in 2000 and 2001, we had two electricity sales agreements with Edison and two with PG&E. Under these contracts, we were paid under an SRAC formula that priced gas off of Topock. On March 27, 2001, the CPUC issued a decision making certain changes in the SRAC formula applicable at that time, the most significant of which was changing the pricing point to Malin, which resulted in a significant reduction in the price we were to be paid by Edison and PG&E. We thereafter entered into a settlement agreement with Edison by which Edison nevertheless agreed to pay using Topock from March 27th forward. The CPUC approved the settlement. However, in various ongoing proceedings, the utilities argued the revised SRAC formula should be retroactively applied to the period from December 2000 to March 27, 2001. The CPUC has indicated in the past it did not believe retroactive adjustment should be made. On February 7, 2008, the CPUC Administrative Law Judge (ALJ) issued an order indicating that the ALJ intended to deal with a pending remand on this issue and ordered the utilities to report the number and identity of QF's still subject to this unresolved issue. We were identified as an affected QF by PG&E but not by Edison. The ALJ also invited interested parties to propose solutions to the pending remand dispute. As no resolution was proposed, on January 26, 2009, the ALJ issued a ruling in this matter in which he proposed a settlement in lieu of continued litigation over this issue. A briefing schedule has been established as to his proposed settlement and out of that briefing will come some determination of whether litigation will continue.

Facility and Contract Summary.

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

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

Employees. On December 31, 2008, we had 303 full-time employees, up from 263 full-time employees on December 31, 2007.

Capital Expenditures Summary (Excluding Acquisitions).

The following is a summary of the developmental capital expenditures incurred during 2008 and 2007 and budgeted capital expenditures for 2009 (in thousands):

	2009 (Budgeted) (1)	2008	2007
S. Midway Asset Team			
New wells and workovers	$ 4,600	$ 32,508	$ 13,174
Facilities - oil & gas	2,800	652	7,576
Facilities - cogeneration	-	828	-
General	-	-	150
	7,400	33,988	20,900
N. Midway Asset Team			
New wells and workovers	12,400	32,477	12,949
Facilities - oil & gas	22,400	33,991	17,125
General	2,100		634
	36,900	66,468	30,708
S. Cal Asset Team			
New wells and workovers	-	12,215	16,627
Facilities - oil & gas	3,500	9,356	17,549
Facilities - cogeneration	500	2,889	604
General	1,150	-	483
	5,150	24,460	35,263
Uinta Asset Team			
New wells and workovers	-	56,491	52,700
Facilities	1,900	2,369	3,151
General	-	-	602
	1,900	58,860	56,453
Piceance Asset Team			
New wells and workovers	5,150	123,982	103,921
Facilities	6,900	4,517	15,298
General	50	1,195	164
	12,100	129,694	119,383
DJ Asset Team			
New wells and workovers	-	14,518	14,017
Facilities	500	2,600	2,736
General	600	190	1,519
	1,100	17,308	18,272
E. Texas Asset Team			
New wells and workovers	34,200	65,412	-
Facilities	700	335	-
	34,900	65,747	-
Other Fixed Assets	550	1,076	4,288
TOTAL	$ 100,000	$ 397,601	$ 285,267

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

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

	2008	2007	2006
Net annual production: (1)			
Oil (Mbbl)	7,441	7,210	7,182
Gas (MMcf)	25,559	15,657	12,526
Total equivalent barrels (MBOE) (2)	11,700	9,819	9,270
Average sales price:			
Oil (per Bbl) before hedging	$ 86.90	$ 57.85	$ 52.92
Oil (per Bbl) after hedging	70.01	53.24	50.55
Gas (per Mcf) before hedging	6.87	4.53	5.48
Gas (per Mcf) after hedging	7.01	5.27	5.57
Per BOE before hedging	70.22	49.72	48.38
Per BOE after hedging	59.81	47.50	46.67
Average operating cost - oil and gas production (per BOE)	17.10	14.38	12.69

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

Acreage and Wells. As of December 31, 2008, our properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	5,322	5,322	653	653	5,975	5,975
Colorado	89,110	70,575	105,714	59,691	194,824	130,266
Kansas	-	-	62,810	61,856	62,810	61,856
Texas	4,794	4,523	-	-	4,794	4,523
Utah (1)	39,280	36,635	183,176	77,779	222,456	114,414
Wyoming	3,520	539	1,746	276	5,266	815
Other	40	3	-	-	40	3
	142,066	117,597	354,099	200,255	496,165	317,852

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

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, 2008, we have 4,093 gross productive wells (3,316 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:

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled:						
Productive	3	2	5	3	7	3
Dry (1)	-	-	-	-	5	1
Development wells drilled:						
Productive	443	374	411	314	532	356
Dry (1)	6	5	7	5	7	5
Total wells drilled:						
Productive	446	376	416	317	539	359
Dry (1)	6	5	7	5	12	6

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

	2008	
	Gross	Net
Total productive wells drilled:		
Oil	248	245
Gas	198	131

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

Company owned drilling rigs. During 2005 and 2006, we purchased three drilling rigs. Owning these rigs allowed us to successfully meet a portion of our drilling needs in Uinta and Piceance. Two of these rigs are leased to a drilling rig operator on a short-term basis and are not currently drilling on the Company's properties and one rig is idle. As the rig market and our rig requirements change, we continue to evaluate the ownership of these rigs and $4.2 million related to the disposal and impairment of certain drilling rigs and related equipment,was recorded in 2008. See Note 13 to the financial statements.

Other. At year end, we had two subsidiaries accounted for under the equity method (see Note 1 to the financial statements). We had no special purpose entities and no off-balance sheet debt. See discussion of our related party transaction at Note 20 to the financial statements.

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 costs. There can be no assurances, however, that changes in, or additions to, laws and regulations regarding the protection of the environment will not have an impact in the future. We maintain insurance coverage that we believe is customary in the industry although we are not fully insured against all environmental or other risks.

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

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

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

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

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

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

Item 1A. Risk Factors

Other Factors Affecting the Company's Business and Financial Results

Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business, results of operations and financial condition. Our revenues, profitability and future growth and reserve calculations depend substantially on the price received for our oil and gas production. 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. Lower prices may also reduce the amount of oil and gas that we can produce economically. The oil and natural gas markets fluctuate widely, and we cannot predict future oil and natural gas prices. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- regional, domestic and foreign supply and perceptions of supply of and demand for oil and natural gas;
- level of consumer demand;
- weather conditions;
- overall domestic and global political and economic conditions
- technological advances affecting energy consumption and supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the capacity, cost and availability of oil and natural gas pipelines and other transportation facilities,
- the price and availability of alternative fuels.

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

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

Our level of indebtedness may limit our financial flexibility. As of December 31, 2008 our total debt was $1.16 billion which is comprised of $200 million outstanding on our 8.25% senior subordinated notes due 2016 and $957 million drawn under our credit facilities.

Our level of indebtedness affects our operations in several ways, including the following:

- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- we may be at a competitive disadvantage as compared to similar companies that have less debt;
- the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants; and
- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings may increase the interest rate and fees we pay on our revolving bank credit facility.

A higher level of indebtedness increases the risk that we may default on our obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

The borrowing base under our credit facility may be insufficient to fund our outstanding debt. The amount we are able to borrow under our senior secured credit facility is determined based on the value of our proved oil and gas reserves and is based on oil and natural gas price assumptions which vary by individual lender. Our borrowing base is subject to redetermination twice each year in April and October with the option for one additional redetermination each year. Should there be a deficiency in the amount of our borrowing base in comparison to our outstanding debt under the facility we would be required to repay any such deficiency in two equal installments, 90 and 180 days after the redetermination.

Our heavy crude in California may be less economic than lighter crude oil and natural gas. As of December 31, 2008, approximately 45% of our proved reserves, or 109 million barrels, consisted of heavy oil. Light crude oil represented 6% and natural gas represented 49% 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. Additionally, most of our crude oil in California is produced using the enhanced oil recovery process of steam injection. This process is generally more costly than primary and secondary recovery methods.

Purchasers of our crude oil and natural gas may become insolvent. We have significant concentrations of credit risk with the purchasers of our crude oil and natural gas. We have had a long-term contract to sell all of our heavy crude oil in California for approximately $8.10 below WTI, the U.S. benchmark crude oil pricing, with Big West of California (BWOC). On December 22, 2008, Flying J, Inc. and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC each filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's production. We have entered into various currently short-term agreements with other companies to sell our California oil production. Pricing and volumes under these agreements vary with prices ranging from just above the posted price for San Joaquin heavy oil to the posted price less a discount. BWOC is evaluating several options, including a sale of the Bakersfield, California refinery. We recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of the $38.5 million due from BWOC, $12.4 million represents December crude oil sales by the Company and represents an administrative claim under the bankruptcy proceedings and $26.1 million represents November crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract. While we also have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, the information received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected nor whether BWOC will assume or reject our agreement.

Additionally, all of our crude oil in Utah is sold under a long-term contract to a single refiner. Under the standard credit terms with our refiners, we may not know that a refiner will be unable to make payment to us until 50 days of our production has been delivered to them. If our purchasers become insolvent, we may not be able to collect any of the amounts owed to us.

We may be unable to meet our drilling obligations. We have drilling obligations in both the Piceance assets in Colorado and our Lake Canyon asset in Utah. In the Piceance basin, we must drill 91 additional wells by February 2011 to avoid penalties of $0.2 million per well and loss of related leases. In Lake Canyon, we must drill an additional 7 wells by November 2009 to avoid the loss of related leases. Our ability to meet these commitments depends on the capital resources available to us to fund our drilling activities and the commodity price environment which affects the economics of these projects.

Our financial counterparties may be unable to satisfy their obligations. We rely on financial institutions to fund their obligations under our senior secured credit facility and make payments to us under our hedging agreements. If one or more of our financial counterparties becomes insolvent, they may not be able to meet their commitment to fund future borrowings under our credit facility which would reduce our liquidity. Additionally, at current commodity prices, a significant portion of our cash flow over the next two years will come from payments from our counterparties on our commodity hedging contracts. If our counterparties are not able to make these payments, our cash flow will be reduced.

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

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

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

We may not be able to deliver minimum crude oil volumes required by our sales contract. Production volumes from our Uinta properties over the next five years are uncertain and there is no assurance that we will be able to consistently meet the minimum contractual requirement. After partial completion of its refinery expansion in Salt Lake City in March 2008, the refiner increased its total purchased volumes to 5,000 Bbl/D. During the term of the contract, the minimum number of delivered barrels ("base daily volume") is 5,000 Bbl/D. In the event that we cannot produce the necessary volume, we may need to purchase crude to meet our contract requirements. Current gross oil production from our Uinta properties is approximately 3,800 Bbl/D.

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 32% of our steam capacity. These facilities are dependent on reasonable power contracts for the sale of electricity. If, for any reason, including if utilities that purchase electricity from us are no longer required by regulation to enter into power contracts with us, we were unable to enter into new or replacement contracts or were to lose any existing contract, we may not be able to supply 100% of the steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements and availability of equipment. The financial cost and timing of such new investment may adversely affect our production, capital outlays and cash provided by operating activities. All of our power contracts expire in 2009 covering our electricity generation.

The future of the electricity market in California is uncertain. We utilize cogeneration plants in California to generate lower cost steam compared to conventional steam generation methods. Electricity produced by our cogeneration plants is sold to utilities and the steam costs are allocated to our oil and gas operations. All of our electricity sales contracts in place with the utilities are currently scheduled to terminate in 2009 and while we intend to enter into future contacts with the utilities all of the terms of such contracts are not known. Additionally legal and regulatory decisions (especially related to the pricing of electricity under the contracts such as the SRAC Decision and the pending issues as to effective dates on retroactivity), can by reducing our electricity revenues adversely affect the economics of our cogeneration facilities and as a result the cost of steam for use in our oil and gas operations.

A shortage of natural gas in California could adversely affect our business. We may be subject to the risks associated with a shortage of natural gas and/or the transportation of natural gas into and within California. We are highly dependent on sufficient volumes of natural gas necessary to use for fuel in generating steam in our heavy oil operations in California. If the required volume of natural gas for use in our operations were to be unavailable or too highly priced to produce heavy oil economically, our production could be adversely impacted. We have firm transportation to move 15,000 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 reducing our exposure to a significant decline in the price of crude oil and natural gas. We also utilize interest rate hedges to fix the rate on a portion of our variable rate indebtedness, as only a portion of our total indebtedness has a fixed rate and we are therefore exposed to fluctuations in interest rates. While the use of hedging transactions limits the downside risk of price declines or rising interest rates, as applicable, their use may also limit future revenues from price increases or reduced expenses from lower interest rates, as applicable. Hedging transactions also involve the risk that the counterparty may be unable to satisfy its obligations.

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

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates. It is not possible to measure underground accumulations of oil or natural gas in an exact way. Estimating accumulations of oil and gas is a complex process that relies on subjective interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC. The accuracy of a reserve estimate is a function of:

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

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

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

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

We capitalize costs to acquire, find and develop our oil and gas properties under the successful efforts accounting method. If net capitalized costs of our oil and gas properties exceed fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties annually and at any time when events or circumstances indicate a review is necessary, based on estimated prices as of the end of the reporting period. The carrying value of oil and gas properties is computed on a field-by-field basis. Once incurred, a writedown of oil and gas properties is not reversible at a later date even if oil or gas prices increase. While we did not have any impairment charges in 2008, it is possible that declining commodity prices could prompt an impairment in the future. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our credit facility.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

There are risks in acquiring producing properties, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of management attention, and costs of increased scope, geographic diversity and complexity of our operations. Increasing our reserve base through acquisitions is an important part of our business strategy. Any acquisition involves potential risks, including, among other things:

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

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

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

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

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

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

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

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

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, 2008) 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, 55, has been President and Chief Executive Officer since June 2004. Mr. Heinemann was Chairman of the Board and interim President and Chief Executive Officer from April 2004 to June 2004. From December 2003 to March 2004, Mr. Heinemann acted as the director designated to serve as the presiding director at executive sessions of the Board in the absences of the Chairman and as liaison between the independent directors and the CEO. Mr. Heinemann joined the Board in March of 2003. From 2000 until 2002, Mr. Heinemann served as the Senior Vice President and Chief Technology Officer of Halliburton Company and as the Chairman of the Halliburton Technology Advisory Committee. He was previously with Mobil Oil Corporation (Mobil) where he served in a variety of positions for Mobil and its various affiliate companies in the energy and technical fields from 1981 to 1999, with his last responsibilities as Vice President of Mobil Technology Company and General Manager of the Mobil Exploration and Producing Technical Center.

DAVID D. WOLF, 38, has been Executive Vice President and Chief Financial Officer since August 2008. Mr. Wolf was previously employed by JPMorgan from 1995 to 2008 where he served as a Managing Director in JPMorgan's Oil and Gas Group.

MICHAEL DUGINSKI, 42, has been Executive Vice President and Chief Operating Officer since September 2007. Mr. Duginski served as Executive Vice President of Corporate Development and California from October 2005 to August 2007; he acted as Senior Vice President of Corporate Development from June 2004 through October 2005 and as Vice President of Corporate Development from February 2002 through June 2004. Mr. Duginski, a mechanical engineer, was previously employed by Texaco, Inc. from 1988 to 2002 where his positions included Director of New Business Development, Production Manager and Gas and Power Operations Manager. Mr. Duginski is also an Assistant Secretary.

DAN ANDERSON, 46, has been Vice President of Rocky Mountains Production since October 2005. Mr. Anderson was Rocky Mountains Manager of Engineering from August 2003 through October 2005. Previously, Mr. Anderson, a petroleum engineer, served as a Senior Staff Petroleum Engineer with Williams Production RMT from August 2001 through August 2003. He also was a Senior Staff Engineer with Barrett Resources from October 2000 through August 2001. He previously held various engineering and management positions with Santa Fe Snyder Corporation and Conoco, Inc. from 1985 to 2000.

WALTER B. AYERS, 65, has acted as Vice President of Human Resources since May 2006. Mr. Ayers was previously a private consultant to the energy industry from January 2002 until his employment with us. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000.

SHAWN M. CANADAY, 33, has held the position of Vice President and Controller since June 2008 and was Interim Chief Financial Officer from June 2008 until August 2008. Mr. Canaday served as Controller from February 2007 to June 2008, as Treasurer from December 2004 to February 2007 and as Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and gas industry since 1998 in various finance functions at Chevron and in public accounting. Mr. Canaday is also an Assistant Secretary.

GEORGE T. CRAWFORD, 48, has been Vice President of California Production since October 2005. Mr. Crawford served as Vice President of Production from December 2000 through October 2005 and as Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, previously served as the Production Engineering Supervisor for Atlantic Richfield Corp. (ARCO) from 1989 to 1998, with numerous engineering and operational assignments, including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

BRUCE S. KELSO, 53, has been Vice President of Rocky Mountains Exploration since October 2005. Mr. Kelso served as Rocky Mountains Exploration Manager from August 2003 through October 2005. Mr. Kelso, a petroleum geologist, previously acted as a Senior Staff Geologist assigned to Rocky Mountain assets with Williams Production RMT, from January 2002 through August 2003. He previously held the position of Vice President of Exploration and Development at Redstone Resources, Inc. from 2000 to 2001.

KENNETH A. OLSON, 53, has been Corporate Secretary since December 1985 and was Treasurer from August 1988 until December 2004.

STEVEN B. WILSON, 45, has been Treasurer since March 2007. Mr. Wilson was Controller or Assistant Controller from November 2003 to February 2007. Before joining us in November 2003, he served as the vice president of finance and administration for Accela, Inc., a software development company, for three years. Prior to that, he held finance functions in select companies and in public accounting. Mr. Wilson is also an Assistant Secretary.

PART II

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

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital Stock," are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $0.50 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 8 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 2008 and 2007 are shown below:

	2008			2007		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 47.20	$ 33.41	$ .075	$ 31.54	$ 27.63	$ .075
Second Quarter	62.15	45.73	.075	41.08	30.41	.075
Third Quarter	61.72	30.99	.075	41.06	31.03	.075
Fourth Quarter	37.76	6.02	.075	49.39	39.30	.075
Total Dividends Paid			$ .300			$ .300

	February 2, 2009	December 31, 2008	December 31, 2007
Berry's Common Stock closing price per share as reported on NYSE Composite Transaction Reporting System	$ 7.36	$ 7.56	$ 44.45

The number of holders of record of our Common Stock was 544 as of February 2, 2009. There was one Class B Shareholder of record as of February 2, 2009.

Dividends. Our regular annual dividend is currently $0.30 per share, payable quarterly in March, June, September and December. We increased our regular quarterly dividend by 15%, from $0.065 to $0.075 per share beginning with the September 2006 dividend.

Since our formation in 1985 through December 31, 2008, we have paid dividends on our Common Stock for 77 consecutive quarters and previous to that for eight consecutive semi-annual periods. We intend to continue the payment of dividends, although future dividend payments will depend upon our level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors. Dividend payments are limited by covenants in our 1) credit facility to the greater of $20 million or 75% of net income, and 2) bond indenture of up to $20 million annually irrespective of our coverage ratio or net income if we have exhausted our restricted payments basket, and up to $10 million in the event we are in a non-payment default.

Equity Compensation Plan Information.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders	3,389,097	$25.16	412,025
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 repurchased 818,000 shares in the open market for approximately $25 million. Our repurchase plan expired in 2006 and no shares were repurchased in 2007 or 2008.

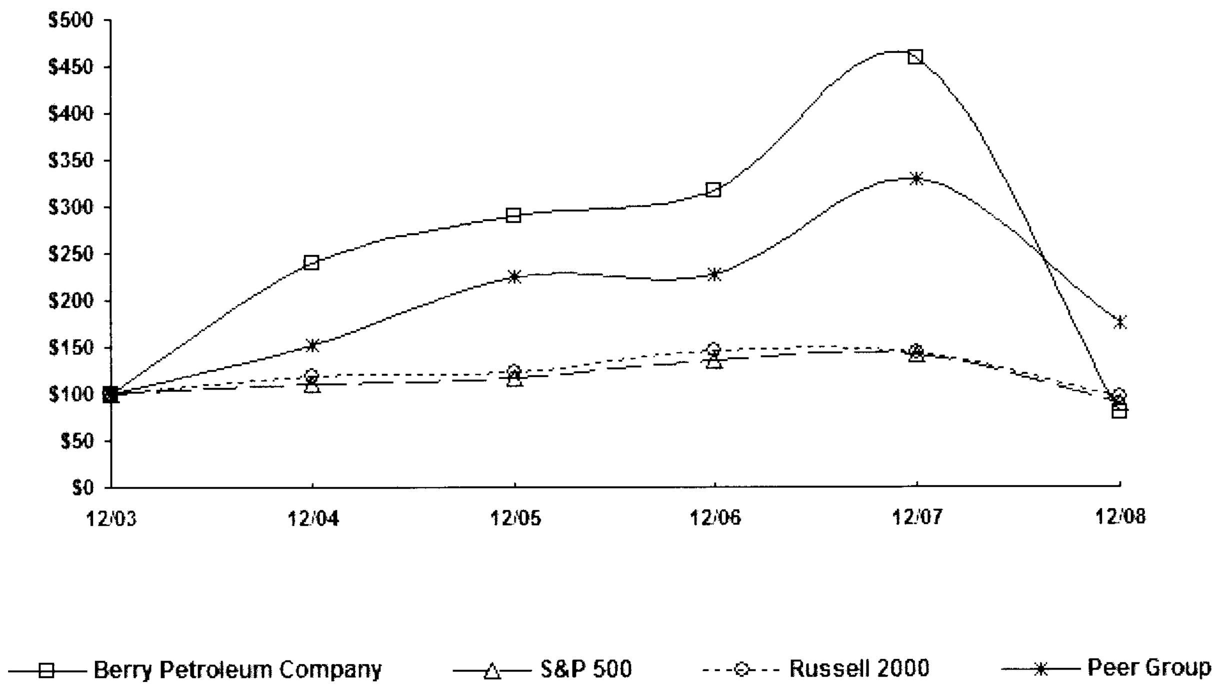
Performance Graph

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, 2003 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index (S&P 500) and a Peer Group, assuming reinvestment of dividends for each measurement period. The information shown is historical and is not necessarily indicative of future performance. The 15 companies which make up the Peer Group are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Encore Acquisition Co., Forest Oil Corp., Petrohawk Energy Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Range Resources Corp., St. Mary Land & Exploration Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Berry Petroleum Company, The S&P 500 Index, The Russell 2000 Index And A Peer Group



*$100 invested on 12/31/03 in stock & index-including reinvestment of dividends.
Fiscal year ending December 31.

	12/03	12/04	12/05	12/06	12/07	12/08
Berry Petroleum Company	100.00	239.51	290.08	317.66	459.24	79.18
S&P 500	100.00	110.88	116.33	134.70	142.10	89.53
Russell 2000	100.00	118.33	123.72	146.44	144.15	95.44
Peer Group	100.00	151.19	224.68	227.29	329.83	175.45

Item 6. Selected Financial Data

The following table sets forth certain financial information and is qualified in its entirety by reference to the historical financial statements and notes thereto included in Item 8 Financial Statements and Supplementary Data. The Statements of Income and Balance Sheet data included in this table for each of the five years in the period ended December 31, 2008 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data).

	2008	2007	2006	2005	2004
Audited Financial Information					
Sales of oil and gas	$ 697,977	$ 467,400	$ 430,497	$ 349,691	$ 226,876
Sales of electricity	63,525	55,619	52,932	55,230	47,644
Gas marketing sales	35,750	-	-	-	-
Gain (loss) on sale of assets (1)	(1,297)	54,173	97	130	410
Operating costs - oil and gas production	200,098	141,218	117,624	99,066	73,838
Operating costs - electricity generation	54,891	45,980	48,281	55,086	46,191
Gas marketing expense	32,072	-	-	-	-
Production taxes	29,898	17,215	14,674	11,506	6,431
General and administrative expenses (G&A)	55,353	40,210	36,841	21,396	22,504
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	138,237	93,691	67,668	38,150	29,752
Electricity generation	2,812	3,568	3,343	3,260	3,490
Net income	133,529	129,928	107,943	112,356	69,187
Basic net income per share	3.00	2.95	2.46	2.55	1.58
Diluted net income per share	$ 2.94	$ 2.89	$ 2.41	$ 2.50	$ 1.54
Weighted average number of shares outstanding (basic)	44,485	44,075	43,948	44,082	43,788
Weighted average number of shares outstanding (diluted)	45,395	44,906	44,774	44,980	44,940
Working capital (deficit)	$ (71,545)	$ (110,350)	$ (116,594)	$ (54,757)	$ (3,840)
Total assets	2,542,383	1,452,106	1,198,997	635,051	412,104
Long-term debt	1,131,800	445,000	390,000	75,000	28,000
Shareholders' equity	827,544	459,974	427,700	334,210	263,086
Cash dividends per share	.30	.30	.30	.30	.26
Cash flow from operations	409,569	238,879	243,229	187,780	124,613
Exploration and development of oil and gas properties	392,769	281,702	265,110	118,718	71,556
Property/facility acquisitions (1)	667,996	56,247	257,840	112,249	2,845
Additions to vehicles, drilling rigs and other fixed assets	$ 4,832	$ 3,565	$ 21,306	$ 11,762	$ 669
Unaudited Operating Data					
Oil and gas producing operations (per BOE):					
Average sales price before hedging	$ 70.22	$ 49.72	$ 48.38	$ 47.01	$ 33.64
Average sales price after hedging	59.81	47.50	46.67	41.62	30.32
Average operating costs - oil and gas production	17.10	14.38	12.69	11.79	10.09
Production taxes	2.56	1.75	1.58	1.37	.86
G&A	4.73	4.09	3.98	2.55	2.99
DD&A - oil and gas production	$ 11.81	$ 9.54	$ 7.30	$ 4.54	$ 3.96
Production (MBOE)	11,700	9,819	9,270	8,401	7,517
Production (MMWh)	755	779	757	741	776
Total proved reserves (BOE)	245,940	169,179	150,262	126,285	109,836
Standardized measure (2)	$ 1,135,581	$ 2,419,506	$ 1,182,268	$ 1,251,380	$ 686,748
Year end average BOE price for PV10 purposes	$ 30.03	$ 66.27	$ 41.23	$ 48.21	$ 29.87
Return on average shareholders' equity	20.74 %	29.18 %	28.33 %	37.63 %	31.06 %
Return on average capital employed	10.33 %	16.01 %	18.21 %	32.74 %	26.29 %

(1) See Note 6 to the financial statements

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

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

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

- Developing our existing resource base
- Investing our capital in a disciplined manner and maintaining a strong financial position
- Calibrating our cost structure to the current commodity price environment
- Acquiring additional assets with significant growth potential
- Accumulating significant acreage positions near our producing operations

Notable Items in 2008.

- Achieved record production which averaged 31,968 BOE/D, up 19% from 2007
- Added 88 million BOE of proved reserves ending 2008 at 245.9 million BOE
- Recorded cash from operating activities of $410 million and funded $398 million of capital expenditures
- Closed on our E. Texas acquisition on July 15, 2008, adding approximately 32 MMcf to daily production
- Placed 5,000 Bbl/d of $100 WTI floor collars for 2009 and 2010 to protect cash flow
- Achieved net income of $134 million
- Drilled 85 wells in the diatomite and increased average production to 1,840 Bbl/D, up 86% from 2007
- Accomplished an 8 day drilling record on a Piceance mesa location and reduced average drilling days to 11
- Drilled 72 gross (44 net) Piceance operated wells which increased net production to average 21 MMcf/D
- Increased the borrowing base on our senior secured credit facility from $550 million to $1.25 billion with an increase in bank commitments to $1.21 billion
- Completed relocation of our corporate headquarters from Bakersfield, California to Denver, Colorado
- David D. Wolf joined the Company as Executive Vice President and Chief Financial Officer
- Temporarily shut in 12,000 Bbl/D in December due to the bankruptcy of Big West Oil in California and recorded an allowance for doubtful accounts of $38.5 million for November and December California crude oil sales
- Resumed California operations in late December, marketing California production to multiple refiners
- Quickly responded to declining commodity price environment reducing rig count from twelve to two during the fourth quarter of 2008, and reducing our 2009 capital budget to $100 million

Notable Items and Expectations for 2009.

- Expecting 2009 capital expenditures of $100 million to be fully funded from operating cash flow
- Anticipating average production between 32,000 and 33,000 BOE/D
- Entered into short-term agreements with multiple refiners to sell all of our California crude oil
- Targeting a 20% reduction in both operating and capital costs for 2009
- Amended the terms of our senior secured credit facility, increasing our maximum EBITDAX to debt ratio

Overview of the Fourth Quarter of 2008. We achieved average production of 35,583 BOE/D in the fourth quarter of 2008, up 1% from an average of 35,149 BOE/D in the third quarter of 2008. We had a net loss of $12.0 million, or $0.27 per diluted share. Net cash from operations was $78 million and capital expenditures during the quarter totaled $92 million. The net loss resulted primarily from a write-off of $38.5 million (pre-tax) of accounts receivable due from BWOC as a result of their bankruptcy filing. This write-off included November and 22 days of December production from the majority of our California properties. We have since contracted with other parties to receive our California production. Other notable charges taken in the fourth quarter of the year included pre-tax rig termination fees of $2.3 million, $4.2 million related to the disposal and impairment of certain drilling rigs and related equipment, and dry hole and impairment expenses of $0.7 million.

View to 2009. Our challenge for 2009 is to calibrate our cost structure to levels that are consistent with those experienced when commodity prices were at $30 Bbl to $50 Bbl. Each of our asset teams is actively pursuing cost reductions and we are targeting a 20% reduction in our non-steam operating costs and our capital costs per well when compared to 2008 levels. Our $100 million capital program is designed to fund high return projects in California and E. Texas and generate excess cash flow.

Capital expenditures. Our capital expenditures for 2008 totaled $398 million for development and were fully funded from our $410 million operating cash flow. We also funded $668 million in acquisitions through additional borrowing on our senior secured credit facility and capitalized $23 million of interest. This compares to our total capital expenditures in 2007 of $341 million, which consisted of $56 million of acquisitions and $285 million in development. We capitalized $18 million of interest in 2007.

Excluding the acquisition of new properties, in 2009 we have a developmental capital program of approximately $100 million which we expect to fund fully out of operating cash flow. As we have operational control of all of our assets and we have limited drilling commitments, we have the ability to revise our capital program based on changes in commodity prices. We expect our capital program will allow us to hold production flat with 2008 levels with average production between 32,000 and 33,000 BOE/D.

Development, Exploitation and Exploration Activity. We drilled 452 gross (381 net) wells during 2008, realizing a gross success rate of 99 percent. As of December 31, 2008, we have two rigs drilling on our properties under long-term contracts.

Drilling Activity. The following table sets forth certain information regarding drilling activities for the year ended December 31, 2008:

	Gross Wells	Net Wells
S. Midway	68	67
N. Midway	103	102
S. Cal	25	25
Piceance	78	46
Uinta	51	50
DJ	107	71
Texas	20	20
Totals *(1)*	452	381

(1) Includes 6 gross wells (5 net wells) that were dry holes in 2008.

Net Oil and Gas Producing Properties at December 31, 2008.

Name, State	% Average Working Interest	Total Net Acres	Proved Reserves (BOE) in millions	Proved Developed Reserves (BOE) in millions	% of Total Proved Reserves	Proved Undeveloped Reserves (BOE) in millions	% of Total Proved Reserves	Average Depth of Producing Reservoir (feet)
S. Midway, CA	98	2,127	52.7	42.8	17%	9.9	4%	1,700
E. Texas	100	4,508	50.0	29.8	12	20.2	8	13,000
Piceance, CO	41	3,157	41.8	13.2	5	28.6	12	9,300
N. Midway, CA	100	1,597	38.9	16.2	7	22.7	9	1,500
Uinta, UT	98	36,635	23.3	10.9	5	12.4	5	6,000
DJ, CO	51	67,418	21.5	13.2	5	8.3	3	2,600
S. Cal, CA	100	1,598	17.7	8.7	4	9.0	4	1,200
Totals		117,040	245.9	134.8	55%	111.1	45%	

Properties

We have seven asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including diatomite (N. Midway), Southern California including Poso Creek and Placerita (S. Cal), Piceance, Uinta, DJ and E. Texas. Our S. Midway, S. Cal and DJ asset teams are primarily focused on production and generate significant cash flow to fund the drilling inventory in our N. Midway, Piceance, E. Texas and Uinta projects.

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

2008 - Capital was focused on adding 20 horizontal wells below existing horizontal wells and further development at Ethel D including drilling 32 producers and the initiation of a pilot steam flood.

2009 - Efforts will be focused on drilling 10 additional, deeper horizontal wells, evaluation of the Ethel D steam flood pilot and lowering operating costs through optimization of well servicing and steam placement.

N. Midway - We began the full scale development of our N. Midway diatomite asset in late 2006 and have drilled 190 wells on this property. The delineation drilling in 2008 increased our original oil in place estimates by 35% to 330 million barrels. We are targeting ultimate recovery between 23% and 40% similar to other diatomite developments in California.

2008 - Capital was focused on drilling approximately 85 diatomite wells, completing major infrastructure upgrades that will support future development, increasing steam injection and further refining our thermal recovery techniques. Production from our diatomite asset increased by 86% in 2008, averaging approximately 1,840 Bbl/D.

2009 - We plan to invest $37 million to drill an additional 44 diatomite wells and install additional steam generation facilities. Additionally, we are seeking operating and capital cost reductions through initiatives such as steam management to improve our steam oil ratio and improved project management to reduce overall well costs. Production is expected to increase over 50% averaging approximately 3,000 Bbl/D.

S. Cal - We acquired the Poso Creek properties in the San Joaquin Valley in early 2003 for approximately $3 million and have proceeded with a successful thermal EOR redevelopment. In the Placerita field in Los Angeles County, we own and operate working interests in thirteen properties, including nine leases and four fee properties. Production relies on thermal recovery methods, primarily steam flooding.

2008 – Capital was directed at a 28 well program at Poso Creek and further expansion of the steam flood including the installation of a fourth steam generator and expansion of our water processing facilities. Average production increased from 1,950 Bbl/D in 2007 to 3,100 Bbl/D in 2008. A fifth steam generator was purchased and installed allowing further steam flood expansion into 2009.

2009 - Production at Poso Creek will increase as the steam flood patterns we developed in 2008 continue to respond. We expect to focus our efforts in 2009 on improving steam-oil ratios and lowering operating expenses.

Piceance - In 2006, we made two separate acquisitions in Piceance in Colorado, targeting the Williams Fork section of the Mesaverde formation. We acquired a 50% working interest in 6,300 gross acres in the Garden Gulch property and a 5% non-operating working interest on 6,300 gross acres and a net operating working interest of 95% in 4,300 gross acres in the North Parachute Ranch property. We spent $312 million to acquire a majority working interest in several blocks of undeveloped acreage located in the Grand Valley field. We believe we have accumulated a sizable resource base with over 900 drilling locations which will allow us to add significant proved reserves over the next several years.

2008 - Production averaged 20,750 Mcf/D in 2008 in comparison to 10,200 Mcf/D in 2007. We operated a four rig drilling program for most of the year and drilled 54 gross (27 net) wells at Garden Gulch and 18 gross (17 net) wells at North Parachute. Significant progress was made during 2008 in reducing the days required to drill wells. During the last three months of drilling activity, the number of drilling days on our mesa wells averaged 10 days on Garden Gulch and 11 days in North Parachute, a 40% reduction in drilling times compared to early 2008.

2009 – Our focus in 2009 will be on reducing our drilling and completion cost structure along with evaluating reservoir parameters and completion practices to improve ultimate recoveries. We believe our focus on cost reduction and improvement of ultimate recovery will allow for attractive returns to continue the development of our over 900 well drilling inventory. We have an inventory of approximately 40 completions and recompletions that we will be evaluating for supplemental capital should commodity prices warrant.

Uinta - The Brundage Canyon leasehold in Duchesne County, northeastern Utah consists of approximately 30,000 undeveloped gross acres which include federal, tribal and private leases. We are targeting the Green River formation that produces both light oil and natural gas. Along with an industry partner, we also hold a 163,000 gross acre block in the Lake Canyon project, which is located immediately west of our Brundage Canyon producing properties. We will drill and operate the shallow wells, targeting light oil and natural gas in the Green River formation and retain up to a 75% working interest. Our partner will drill and operate deep wells that will target hydrocarbons in the Mesaverde and Wasatch formations. We will hold up to a 25% working interest in these deep wells. The Ute Tribe has the option to participate in each well and obtain a 25% working interest which would reduce our and our partner's participation.

2008 – Production averaged 6,142 BOE/D in 2008 compared to 5,743 BOE/D in 2007. We drilled 51 gross (50 net) wells in the Uinta project which included 39 wells at Brundage Canyon, 8 wells in the Ashley Forest and 4 Green River wells at Lake Canyon. The Ashley Forest results continue to be encouraging with the 2008 wells achieving recoveries similar to Brundage Canyon. Three of our Lake Canyon wells are waiting on completion which is scheduled for mid-2009.

2009 – In 2009 capital is primarily directed at facility upgrades, pursuing the remaining three Lake Canyon completions and the completion of the Ashley Forest Environmental Impact Study (EIS) which we anticipate in the first half of 2009.

DJ - In 2005, we made three acquisitions for approximately $111 million establishing a core area in the Niobrara gas producing assets in eastern Colorado, western Kansas, and southwestern Nebraska. In 2007, we divested of our Kansas and Nebraska positions and focused our development in Yuma County where we have approximately 110,000 net acres and over 1,100 producing wells. Our Yuma County Niobrara projects provide sustainable and steady cash flow resulting from low capital development costs, modest production declines and long-life reserves.

2008 – Production averaged 19,700 net Mcf/D in 2008 compared to 18,700 Mcf/D in 2007. In 2008 we drilled 107 Niobrara development wells (71 net) in Yuma County with a 100% success rate and expanded our gathering and compression infrastructure to facilitate our drilling program. Early in the year we acquired an additional 75 square miles of 3-D seismic data. Interpretation of the 2008 seismic program and re-evaluation of previous year's acquisitions continue to replenish our low risk repeatable drilling inventory and provide additions to our proved reserves.

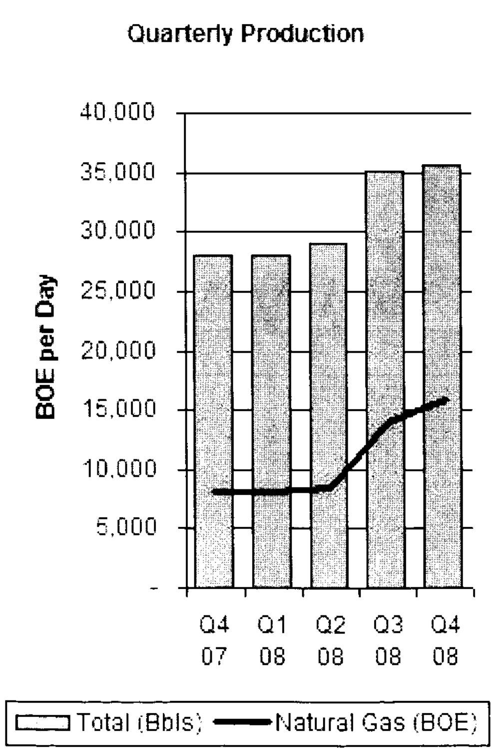
2009 – The primary focus in 2009 will be to maximize production from our existing wells, increase operational efficiencies, and reduce lease operating expense. Our capital program will be directed toward lease acquisition and facility infrastructure upgrades.

E. Texas – On July 15, 2008, we acquired a 100% working interest in natural gas producing properties on 4,500 net acres in Limestone and Harrison counties in East Texas for approximately $650 million. In Limestone County, we are targeting seven productive sands including the Cotton Valley and Bossier sands at depths between 8,000 and 13,000 feet. In Harrison County, we are targeting five productive sands with average depths between 6,500 and 13,000 feet and have upside potential in the Haynesville and Bossier Shales. We assumed operations from the seller on November 1, 2008.

2008 - We executed a five rig program in 2008 and 19 wells have been drilled and put on production since closing (4 in Harrison and 15 in Limestone). We also drilled three wells which are awaiting completion during 2009.

2009 - We plan to run one rig during 2009 and will drill approximately five vertical wells in the Oakes field during the year and plan to begin drilling horizontal wells in the Haynesville Shale Darco field in the third quarter of 2009.

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



Revenues. Approximately 87% 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. Approximately 8% of our revenues are derived from electricity sales from cogeneration facilities which supply approximately 32% 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. The remaining 5% of our revenues are primarily derived from gas marketing sales which represent excess capacity on the Rockies Express pipeline which we used to market natural gas for our working interest partners.

Sales of oil and gas were up 49% in 2008 compared to 2007 and up 62% from 2006. This improvement was due to an overall increase in both oil and gas production levels and increased oil prices. Improvements in production volume reflect the successful results of capital investments. Oil and natural gas prices contributed roughly 73% of the revenue increase and the increase in production volumes contributed the other 27%. Approximately 64% of our oil and gas sales volumes in 2008 were crude oil, with 82% of the crude oil being heavy oil produced in California which was sold under a contract based on the higher of WTI minus a fixed differential or the average posted price plus a premium.

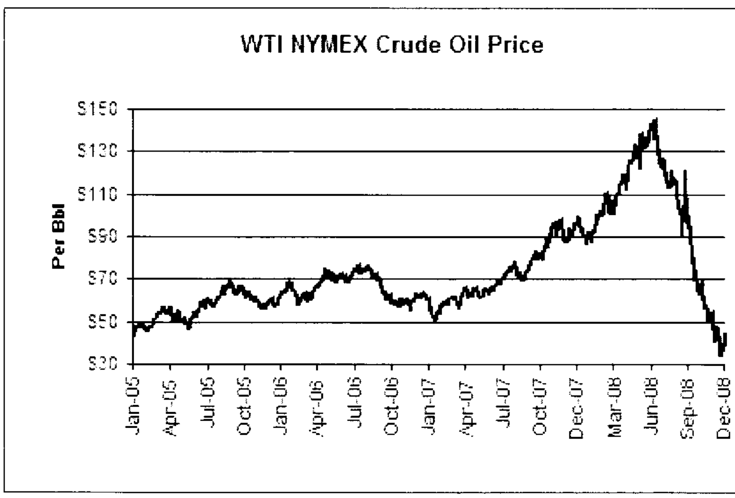
The following results are in millions (except per share data) for the years ended December 31:

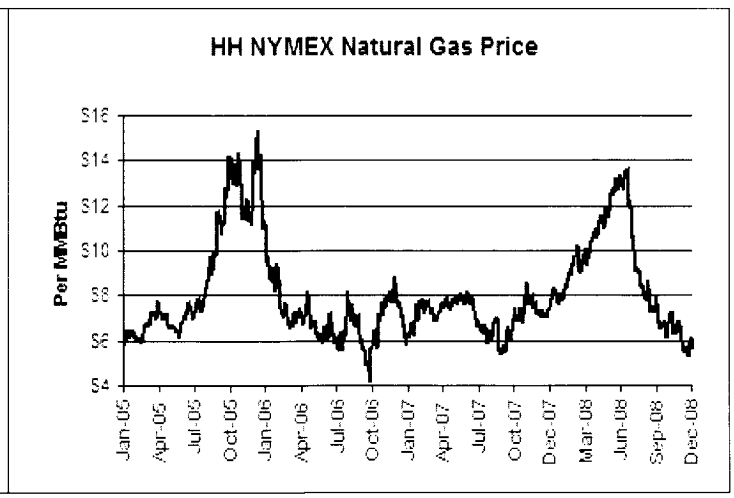
	2008	2007	2006
Sales of oil	$ 519	$ 385	$ 360
Sales of gas	179	82	70
Total sales of oil and gas	$ 698	$ 467	$ 430
Sales of electricity	64	56	53
Gas marketing	36	-	-
Gain (loss) on sale of assets (1)	(1)	54	1
Interest and other income, net	5	6	2
Total revenues and other income	$ 802	$ 583	$ 486
Net income	$ 134	$ 130	$ 108
Earnings per share (diluted)	$ 2.94	$ 2.89	$ 2.41

(1) Includes 2007 sale of Montalvo, California assets

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

	December 31, 2008	December 31, 2007	September 30, 2008
Sales of oil	$ 97	$ 109	$ 145
Sales of gas	43	24	63
Total sales of oil and gas	$ 140	$ 133	$ 208
Sales of electricity	12	15	18
Gas marketing	8	-	13
Gain (loss) on sale of assets	(2)	2	-
Interest and other income, net	2	3	2
Total revenues and other income	$ 160	$ 153	$ 241
Net income (loss)	$ (12)	$ 32	$ 53
Net income (loss) per share (diluted)	$ (.27)	$ .71	$ 1.17





Oil Contracts. See Item 1 Business.

Hedging. See Item 7A Quantitative and Qualitative Disclosures about Market Risk and Note 18 to the financial statements.

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

		2008	%		2007	%		2006	%
Oil and Gas									
Heavy Oil Production (Bbl/D)		16,633	52		16,170	60		15,972	63
Light Oil Production (Bbl/D)		3,697	12		3,583	13		3,707	15
Total Oil Production (Bbl/D)		20,330	64		19,753	73		19,679	78
Natural Gas Production (Mcf/D)		69,834	36		42,895	27		34,317	22
Total (BOE/D)		31,968	100		26,902	100		25,398	100
Percentage increase from prior year		19%			6%			10%	
Per BOE:									
Average sales price before hedging	$	70.22		$	49.72		$	48.38	
Average sales price after hedging		59.81			47.50			46.67	
Oil, per Bbl:									
Average WTI price	$	99.75		$	72.41		$	66.25	
Price sensitive royalties		(2.95)			(5.03)			(5.13)	
Gravity differential and other		(11.32)			(9.53)			(8.20)	
Crude oil hedges		(16.89)			(4.61)			(2.37)	
Correction to royalties payable		1.42			-			-	
Average oil sales price after hedging	$	70.01		$	53.24		$	50.55	
Natural gas price:									
Average Henry Hub price per MMBtu	$	9.04		$	7.12		$	6.97	
Conversion to Mcf		.45			.34			.33	
Natural gas hedges		.14			.74			.09	
Location, quality differentials and other		(2.62)			(2.93)			(1.82)	
Average gas sales price after hedging	$	7.01		$	5.27		$	5.57	

Production increased 19% or 5,066 BOE/D for the year ended December 31, 2008 when compared to the year ended December 31, 2007. Our E. Texas acquisition which closed on July 15, 2008, contributed 2,384 BOE/D on an annualized basis. Our development activities during the year resulted in increases in the Piceance, Poso and diatomite of 1,796 BOE/D, 1,133 BOE/D and 851 BOE/D, respectively.

The following table is for the three months ended:

		December 31, 2008	%		December 31, 2007	%		September 30, 2008	%
Oil and Gas									
Heavy Oil Production (Bbl/D)		15,999	45		16,595	59		17,264	49
Light Oil Production (Bbl/D)		3,659	10		3,395	12		3,898	11
Total Oil Production (Bbl/D)		19,658	55		19,990	71		21,162	60
Natural Gas Production (Mcf/D)		95,548	45		48,196	29		83,928	40
Total (BOE/D)		35,583	100		28,023	100		35,150	100
Per BOE:									
Average sales price before hedging	$	38.45		$	60.38		$	80.22	
Average sales price after hedging		42.93			52.32			64.98	
Oil, per Bbl:									
Average WTI price	$	59.08		$	90.50		$	118.22	
Price sensitive royalties		(1.69)			(6.68)			(5.30)	
Gravity differential and other		(8.55)			(9.92)			(10.80)	
Crude oil hedges		4.69			(13.57)			(26.12)	
Average oil sales price after hedging	$	53.53		$	60.33		$	76.00	
Natural gas price:									
Average Henry Hub price per MMBtu	$	6.95		$	7.39		$	10.24	
Conversion to Mcf		.35			.35			.52	
Natural gas hedges		.70			.91			.15	
Location, quality differentials and other		(3.02)			(3.21)			(2.81)	
Average gas sales price after hedging	$	4.98		$	5.44		$	8.10	

Electricity. We consume natural gas as fuel to operate our three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the cost-effective production of heavy oil. We sell our electricity to utilities under standard offer contracts based on "avoided cost" or SRAC pricing approved by the CPUC and under which our revenues are currently linked to the cost of natural gas. Natural gas index prices are the primary determinant of our electricity sales price based on the current pricing formula under these contracts. The correlation between electricity sales and natural gas prices allows us to manage our cost of producing steam more effectively. Revenues were up and operating costs were up in the year ended 2008 from the year ended 2007 due to 18% higher electricity prices and 27% higher natural gas prices, respectively. Revenues were up and operating costs were down in the year ended 2007 from the year ended 2006 due to 2% higher electricity prices and 6% lower natural gas prices, respectively. We purchased approximately 27 MMBtu/D as fuel for use in our cogeneration facilities in both the year ended December 31, 2008 and the year ended December 31, 2007. In 2007 and 2008, our electricity operations improved partially from the lower cost of our firm transportation natural gas we purchased. We purchase and transport 12,000 average MMBtu/D on the Kern River Pipeline under our firm transportation contract and use this gas to produce conventional and cogeneration steam in the Midway-Sunset field. The differential between Rocky Mountain gas prices and Southern California Border prices increased during 2007 and 2008 compared to 2006 allowing us to purchase a portion of our gas at prices less than the Southern California Border price. As our electricity revenue is linked to Southern California Border prices, the fuel we purchased at lower Rocky Mountain prices was the primary contributor to the increase in our electricity margins in 2007 and 2008 compared to 2006.

On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes the way SRAC energy prices will be determined for existing and new SO contracts and revises the capacity prices paid under current SO1 contracts. The effective date of the SRAC Decision has not been determined nor has every element of the formula under the SRAC Decision been finalized. As such it is not possible to predict the economic impact on us of the SRAC Decision nor whether its terms will be applied retroactively and if so, for what period.

The following table is for the years ended December 31:

	2008	2007	2006
Electricity			
Revenues (in millions)	$ 63.5	$ 55.6	$ 52.9
Operating costs (in millions)	$ 54.9	$ 46.0	$ 48.3
Decrease to total oil and gas operating expenses per barrel	$ .74	$ .98	$ .50
Electric power produced - MWh/D	2,063	2,133	2,074
Electric power sold - MWh/D	1,873	1,932	1,867
Average sales price/MWh (no hedging was in place)	$ 92.98	$ 78.62	$ 77.13
Fuel gas cost/MMBtu (including transportation)	$ 7.95	$ 6.08	$ 6.44

Royalties. A price-sensitive royalty burdens certain of our S. Midway properties which produced approximately 2,300 BOE/D in 2008. This royalty was 75% of the amount of the heavy oil posted price above a base price which was $16.11 in 2008. This royalty rate was reduced to 53% effective January 1, 2008 as long as we maintain a minimum steam injection level. We met the steam injection level in 2008 and expect to meet the requirement going forward. This base price escalates at 2% annually, thus the threshold price is $16.43 per barrel in 2009. Liabilities payable for these royalties were $22 million, $36 million and $36 million in the years ended December 31, 2008, 2007 and 2006, respectively.

In the first quarter of 2008, we determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. We concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, the error was corrected during the first quarter of 2008, with the effect of increasing our sales of oil and gas by $10.5 million and reducing our royalties payable.

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)		
	2008	2007	Change	2008	2007	Change
Operating costs - oil and gas production	$ 17.10	$ 14.38	19 %	$ 200,098	$ 141,218	42%
Production taxes	2.56	1.75	46 %	29,898	17,215	74%
DD&A - oil and gas production	11.81	9.54	24 %	138,237	93,691	48%
G&A	4.73	4.09	16 %	55,353	40,210	38%
Interest expense	2.24	1.76	27 %	26,209	17,287	52%
Total	$ 38.44	$ 31.52	22 %	$ 449,795	$ 309,621	45%

Our total operating costs, production taxes, G&A and interest expenses for 2008, stated on a unit-of-production basis, increased 22% over 2007. The changes were primarily related to the following items:

- Operating costs: Our operating costs increased primarily due to higher contract services and labor costs, higher compression, gathering, and dehydration costs and higher steam costs resulting from higher volumes of injected steam. Of the $59 million increase in operating expense compared to 2007, approximately $31 million was due to higher steam costs and approximately $4 million was due to the addition of our E. Texas assets. On a per barrel basis, E. Texas operating costs approximate $1.00/Mcf and reduces our overall cost per barrel. The following table presents steam information:

	2008	2007	Change
Average volume of steam injected (Bbl/D)	99,908	87,990	14%
Fuel gas cost/MMBtu (including transportation)	7.95	$ 6.08	31%

Based on current plans, we are targeting average steam injection in 2009 of approximately 120,000 BSPD or a 20% increase compared to 2008.

- Production taxes: Our production taxes have increased over the last year as the value of our oil and natural gas has increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. We expect production taxes to track oil and gas prices generally.

- Depreciation, depletion and amortization: DD&A increased per BOE in 2008 by 24% from 2007. Over the past year this increase has resulted from an increase in capital spending in fields with higher drilling and leasehold acquisition costs, which is in line with our expectations. Additionally, DD&A may continue to trend higher as a certain portion of our interest cost related to our Piceance acquisitions is capitalized into the basis of the assets. We anticipate a portion will continue to be capitalized over the next several years until our probable reserves have been recategorized to proved reserves.

- General and administrative: Approximately 65% of our G&A is related to compensation. The primary reason for the increase in G&A during 2008 was a 15% increase in employee headcount associated with our E. Texas acquisition and the development of our assets. In 2008 we moved our corporate headquarters from Bakersfield, California to Denver, Colorado and approximately $1.7 million was related to relocation of our employees and related expenses. Also included in G&A is $2.3 million in rig termination penalties that we incurred during the fourth quarter of 2008 and $0.6 million for costs we incurred to evaluate the formation of a master limited partnership.

- Interest expense: Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, was $1.16 billion at December 31, 2008 compared to $459 million at December 31, 2007. Average borrowings in 2008 increased primarily due to our E. Texas acquisition. For the year ended December 31, 2008, $23 million of interest cost has been capitalized.

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

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

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

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

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

- Production taxes: During 2007 our production taxes increased over 2006 as the value of our oil and natural gas had increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves.

- Depreciation, depletion and amortization: DD&A increased per BOE in 2007 by 31% from 2006 due to an increase in capital spending in fields with higher drilling and leasehold acquisition costs.

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

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

Estimated 2009 Oil and Gas Operating, G&A and Interest Expenses. We estimate our 2009 production volume will range between 32,000 BOE/D and 33,000 BOE/D. Based on WTI of $47.50 and NYMEX HH of $5.00 MMBtu, we expect our expenses to be within the following ranges:

	Amount per BOE					
		Anticipated range in 2009		2008		2007
Operating costs-oil and gas production (1)	$	13.50 – 15.00	$	17.10	$	14.38
Production taxes (2)		1.50 – 2.00		2.56		1.75
DD&A		14.00 – 16.00		11.81		9.54
G&A		3.75 – 4.00		4.73		4.09
Interest expense		3.00 – 4.00		2.24		1.76
Total	$	35.75 – 41.00	$	38.44	$	31.52

(1) *We expect operating costs to decrease in 2009 as compared to 2008 due to lower natural gas prices which are the primary driver of our cost to generate steam in California and our overall cost reduction efforts.*

(2) *We expect production taxes will be lower on a per BOE basis as our averaged realized price decreases due to lower commodity prices and a majority of these costs are based on a percentage of our revenue.*

Dry hole, abandonment, impairment and exploration. In 2008 we had dry hole, abandonment and impairment charges of $12.3 million. We recorded $7.3 million for technical difficulties that were encountered on five wells in Piceance before reaching total depth. These holes were abandoned in favor of drilling to the same bottom hole location by drilling new wells. We incurred exploration costs of $2.4 million in 2008 compared to $0.7 million and $3.8 million in 2007 and 2006, respectively. These costs consist primarily of geological and geophysical costs in DJ. Due to the release of our rigs we performed an impairment test which resulted in $2.4 million of impairment costs resulting from the impairment of one rig. Additionally, we performed an impairment test of our oil and gas assets at December 31, 2008 in accordance with SFAS 144 and determined that no impairment was necessary.

In 2007 we had dry hole, abandonment and impairment charges of $13.7 million consisting primarily of a $4.6 million write down of a portion of our Tri-State acreage in connection with the then current and pending sale of these properties, a $3.3 million impairment of our Coyote Flats prospect to reflect its fair value in conjunction with the preparation of our year end reserve estimates, a $2.9 million write down of our Bakken properties sold in September 2007, and other dry hole charges of $2.2 million.

Bad debt expense. In December 2008, Flying J, Inc. and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Of the $38.7 million recorded in bad debt expense for the year ended December 31, 2008, $38.5 million relates to the allowance for bad debt taken for the bankruptcy of BWOC with the remainder due to the bankruptcy of SemCrude earlier in 2008. Of the $38.5 million due from BWOC, $12.4 million represents December crude oil sales by the Company and represents an administrative claim under the bankruptcy proceedings and $26.1 million represents November crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract for any amounts received by us under our short-term contracts which are less than what we would have otherwise received from BWOC had they been able to accept our production. We have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that our claim is not fully collectible from BWOC. While we believe that we may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected nor as to whether BWOC will assume or reject our contract.

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. This credit is based on the average wellhead prices for the prior year. While we do not expect to generate EOR credit in 2009, we would expect to generate some EOR tax credit for 2010 if average U.S. wellhead oil prices in 2009 are within an approximate range of $44 to $50. As of December 31, 2008, we have approximately $24 million of federal and $17 million of state (California) EOR tax credit carryforwards available to reduce future cash income taxes. The EOR credits will begin to expire, if unused, in 2024 and 2015 for federal and California purposes, respectively.

We experienced an effective tax rate of 37%, 38% and 39% in 2008, 2007 and 2006, respectively. The rate is lower than our combined federal and state statutory tax rate of 40% primarily due to certain business incentives. We expect our effective tax rate to range between 37% and 38% in 2009, given the current commodity price environment. See Note 12 to the financial statements for further information.

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

On January 2, 2008 we entered into NYMEX swaps to protect our DJ cash flows. These natural gas derivatives were not correlated at inception, and therefore ineffective. On January 14, 2008, we entered into basis swaps and designated the combination of the basis swaps and NYMEX swaps as cash flow hedges. However, we took a charge of $357,000 to Commodity Derivatives in the first quarter of 2008 which reflected the ineffectiveness for the interim period.

Most of our oil hedges are based on the West Texas Intermediate (WTI) index and our California oil sales contract with BWOC is tied to WTI which has allowed us to qualify for hedge accounting and effectively hedge our production. Our interim sales contracts are primarily based on the field posting price and we are therefore subject to potential ineffectiveness. There is a high correlation between WTI and the field posting prices which allowed us to continue hedge accounting. Additionally, under the dollar offset method, we did not have any ineffectiveness under these contracts during 2008. However, depending on the change in value of our actual hedges compared to a hypothetical hedge based on field posting prices, we may have significant ineffectiveness on these contracts in the future based on changes in the field posted price compared to the changes in WTI.

Asset dispositions. We have significantly increased and strengthened our portfolio of assets since 2002 and expect to continue to make acquisitions. We anticipate that we will dispose of certain properties or assets over time. The assets most likely for disposition will be those that do not fit or complement our strategic growth plan, that are not contributing satisfactory economic returns given the profile of the assets, or that we believe the development potential will not be meaningful to us as a whole. We divested several assets in 2007. Proceeds from these sales contributed to the funding of our capital program. Net oil and gas properties and equipment classified as held for sale is zero at December 31, 2008 and $1.4 million as of December 31, 2007 in accordance with SFAS No. 144. See Note 3 to the financial statements.

Financial Condition, Liquidity and Capital Resources. Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development and exploration drilling and the acquisition of properties. Fluctuations in commodity prices, production rates and operating expenses have been the primary reason for changes in our cash flow from operating activities.

Liquidity. In October 2006, we completed the sale of $200 million of ten year 8.25% senior subordinated notes and paid down our borrowings under our facility. In July 2008 we secured our credit facility with our assets and as of December 31, 2008 we had bank commitments of $1.21 billion with a borrowing base of $1.25 billion. As of December 31, 2008, we had total borrowings under the senior secured revolving credit facility and money market line of credit of $957 million and $200 million under our senior subordinated notes. Our available credit under our senior secured credit facility was $245 million at year-end 2008.

Our borrowing base is subject to semi-annual redeterminations in April and October of each year. The borrowing base is determined by each lender based on the value of our proved oil and gas reserves using price assumptions that vary by lender. Due to a decline in commodity prices, it is likely that our borrowing base will decrease in April 2009 which could substantially reduce our liquidity. Should the amount of our borrowing base decrease below the amount outstanding under the facility, we would be required to repay any such deficiency in two equal installments 90 and 180 days after the borrowing base redetermination. Hedges generally add significant value to our borrowing base as the prices banks use to value our assets are at a discount to futures prices. We have a minimal amount of our oil production hedged after 2010 and we will likely enter into additional hedge positions as needed to increase our borrowing base under the senior secured credit facility. In addition to amending our covenants to increase the amount of total leverage we may incur, the February 2009 amendment to our credit facility provides us with the flexibility to add various forms of debt that is junior to our senior secured credit facility and that is not subject to a borrowing base. We are evaluating such junior debt to further increase our liquidity.

Capital Expenditures and Cash Flows. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. Acquisitions are typically debt financed. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flow. Excess cash generated from operations is expected to be applied toward debt reduction or other corporate purposes. As we operate all of our assets, we have the flexibility to modify our capital program based on changes in commodity prices. In 2009, we have a capital program of approximately $100 million and we expect to fully fund this program from operating cash flow which should approximate $175 million. Approximately 90% of our oil production is hedged for 2009 and thus our sensitivity to changes in oil prices is limited. A ten dollar change in oil prices impacts our operating cash flow by approximately $2 million in 2009. A one dollar change in natural gas prices impacts operating cash flow by approximately $6 million.

Dividends. Our regular annual dividend is currently $0.30 per share, or approximately $13.4 million annually, payable quarterly in March, June, September and December.

Working Capital. 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 decreased in 2008 (see graphs on page 32) and we increased production by 19%.

Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit arrangements. We use 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 2009, we expect our working capital deficit to decrease by $50 to $65 million as our accounts payable is reduced to reflect a $100 million capital budget compared to a $400 million capital budget in 2009 and our price sensitive royalty in California which is paid annually in February of each year is reduced due to lower commodity prices.

In July 2008, we completed the purchase of 4,500 net acres in E. Texas for approximately $650 million which was funded from our senior secured credit facility.

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

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):

		2008		2007	Change
Average production (BOE/D)		31,968		26,902	19%
Average oil and gas sales prices, per BOE after hedging	$	59.81	$	47.50	26%
Net cash provided by operating activities	$	410	$	239	72%
Working capital (deficit)	$	(72)	$	(110)	38%
Sales of oil and gas	$	698	$	467	50%
Total debt	$	1,157	$	459	152%
Capital expenditures, including acquisitions and deposits on acquisitions	$	1,066	$	342	212%
Dividends paid	$	13.4	$	13.3	1%

Hedging. See Item 7A Quantitative and Qualitative Disclosures about Market Risk and Note 18 to the financial statements.

Credit Facility. See Note 7 to the financial statements for more information.

Contractual Obligations.

Our contractual obligations as of December 31, 2008 are as follows (in thousands):

	Total	2009	2010	2011	2012	2013	Thereafter
Long-term debt and interest	$ 1,471,383	$ 82,211	$ 56,558	$ 56,558	$ 56,558	$ 969,998	$ 249,500
Abandonment obligations	41,967	1,643	1,642	1,642	1,642	1,642	33,756
Operating lease obligations	18,328	2,373	2,390	2,436	2,446	2,493	6,190
Drilling and rig obligations	47,049	12,789	8,030	8,030	18,200	-	-
Firm natural gas transportation contracts	165,071	19,803	19,803	19,803	19,652	17,557	68,453
Total	$ 1,743,798	$ 118,819	$ 88,423	$ 88,469	$ 98,498	$ 991,690	$ 357,899

Long-term debt and interest - Our credit facility borrowings and related interest of approximately 4.3% can be paid before its maturity date without significant penalty. Our bond notes and related interest of 8.25% mature in November 2016, but are not redeemable until November 1, 2011 and are not redeemable without any premium until November 1, 2014.

Operating leases - We lease corporate and field offices in California, Colorado and Texas. Rent expense with respect to our lease commitments for the years ended December 31, 2008, 2007 and 2006 was $1.7 million, $1.5 million and $1.0 million, respectively. In 2006, we purchased an airplane for business travel which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

Drilling obligations – Starting in 2006, we began to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the four year contract. Our minimum obligation under our exploration and development agreement is $9.6 million, and as of December 31, 2008 the remaining obligation is $2.4 million. Also included above, under our June 2006 joint venture agreement in Piceance we are required to have 120 wells drilled by February 2011 to avoid penalties of $0.2 million per well or a maximum of $24 million. As of December 31, 2008 we have drilled 29 of these wells and anticipate resuming drilling in early 2010 to continue the progression towards meeting our commitment.

Drilling rig obligations - We are obligated in operating lease agreements for the use of two drilling rigs, one in California and one of which resulted from our July, 2008 E. Texas Acquisition (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Properties).

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

Other obligations. We adopted the provisions of FIN No. 48 on January 1, 2007 and recognized no material adjustment to retained earnings. As of December 31, 2008, we had a gross liability for uncertain tax benefits of $12 million of which $10 million, if recognized, would affect the effective tax rate. We recognize potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. As of December 31, 2008, we had accrued approximately $1.2 million of interest related to our uncertain tax positions. Due to the uncertainty about the periods in which examinations will be completed and limited information related to current audits, we are not able to make reasonably reliable estimates of the periods in which cash settlements will occur with taxing authorities for the noncurrent liabilities.

On February 27, 2007, we entered into a multi-staged crude oil sales contract through June 30, 2013 with a refiner for the purchase of our Uinta light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D on July 1, 2007. After partial completion of its refinery expansion in Salt Lake City in March 2008, the refiner increased its total purchase notional volumes to 5,000 Bbl/D. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI, and ranges between $10 and $15 at WTI prices between $40 and $60. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company's paraffinic crude oil can vary seasonally and this contract provides a stable outlet for the Company's crude oil.

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. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that economic proved reserves have been discovered may take considerable time and judgment. The evaluation of oil and gas leasehold acquisition costs included in unproved properties requires management's judgment to estimate the fair value of such properties.

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

Carrying Value of Long-lived Assets. Downward revisions in our estimated reserve quantities, increases in future cost estimates or depressed crude oil or natural gas prices could cause us to reduce the carrying amounts of our properties. We perform an impairment analysis of our proved properties annually, or when current events or circumstances indicate that carrying amounts may not be recoverable, by comparing the future undiscounted net revenue to the net book carrying value of the assets. An analysis of the proved properties will also be performed whenever events or changes in circumstances indicate an asset's carrying value may not be recoverable from future net revenue. Assets are grouped at the field level and, if it is determined that the net book carrying value cannot be recovered by the estimated future undiscounted cash flow, they are written down to fair value. Cash flows used in the impairment analysis are determined based on our estimates of crude oil and natural gas reserves, future crude oil and natural gas prices and costs to extract these reserves. For our unproved properties, we perform an impairment analysis annually or whenever events or changes in circumstances indicate an asset's net book carrying value may not be recoverable. These evaluations involve a significant amount of judgment since the results are based on estimated future sales prices, costs to produce these products, estimates of oil and natural gas reserves to be recovered and the timing of development.

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

Income Taxes. We compute income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes* as interpreted by FIN 48, *Accounting for Uncertainty in Income Taxes*. SFAS No. 109 requires an asset and liability approach which results in the recognition of deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each calendar year as well as the effects of tax rate changes, tax credits, and tax credit carryforwards. A valuation allowance is recognized if it is determined that deferred tax assets may not be fully utilized in future periods. We may generate EOR tax credits from the production of our heavy crude oil in California which may result in a deferred tax asset. We believe that these credits will be fully utilized in future years and consequently have not recorded any valuation allowance related to these credits. Due to uncertainties involved with tax matters, the future effective tax rate may vary significantly from the estimated current year effective tax rate. FIN 48 clarifies the accounting for income taxes by prescribing the minimum recognition threshold an uncertain tax position is required to meet before tax benefits associated with such uncertain tax positions are recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 excludes income taxes from the scope of SFAS No. 5, *Accounting for Contingencies*. FIN 48 also requires that amounts recognized in the Balance Sheet related to uncertain tax positions be classified as a current or noncurrent liability, based upon the expected timing of the payment to a taxing authority.

Asset Retirement Obligations. We have significant obligations to plug and abandon oil and natural gas wells and related equipment at the end of oil and gas production operations. The computation of our asset retirement obligations (ARO) was prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires us to record the fair value of liabilities for retirement obligations of long-lived assets. Estimating the future ARO requires management to make estimates and judgments regarding timing, current estimates of plugging and abandonment costs, as well as to determine what constitutes adequate remediation. We develop estimates based on our historical costs and estimated costs where we do not have such historical data and use the present value of estimated cash flows related to our ARO to determine the fair value. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Changes in any of these assumptions can result in significant revisions to the estimated ARO. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment will be made to the related asset. Due to the subjectivity of assumptions and the relatively long life of our assets, the ultimate costs to retire our wells may vary significantly from previous estimates.

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

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

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

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

The E. Texas purchase price was based on the relative fair values, as determined by the valuation of proved reserves and related assets as of the acquisition date.

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

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

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

Recent Accounting Pronouncements. In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. This interpretation requires that realization of an uncertain income tax position must be "more likely than not" (i.e. greater than 50% likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, this interpretation prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. This interpretation also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. We adopted this interpretation in the first quarter of 2007. See Note 12.

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. We adopted this Statement in 2008 and increased our disclosures accordingly. SFAS No. 157-2 addresses the same topic for nonfinancial assets and liabilities and will become effective for our fiscal year beginning January 1, 2009. We do not believe that the implementation of SFAS 157-2 will have a material impact on our financial statements.

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. We adopted this statement January 1, 2008 and it did not have a material effect on our financial statements.

In April 2007, the FASB issued a FASB Staff Position to amend FASB Interpretation 39, *Offsetting of Amounts Related to Certain Contracts*. FIN 39-1 states that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with paragraph 10 of Interpretation 39. FIN 39-1 became effective for our fiscal year beginning January 1, 2008 and did not have any effect on our financial statements as we do not post collateral under our hedging agreements.

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

In September 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Positions (FSP) No. 133-1 and FIN 45-4 to amend FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to require disclosures by sellers of credit derivatives, including credit derivatives embedded in a hybrid instrument. This FSP also amends FASB Interpretation No.45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*, to require an additional disclosure about the current status of the payment/performance risk of a guarantee. Further, this FSP clarifies the FASB's intent about the effective date of FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*. This FSP was adopted in 2008 and did not have a material effect on our financial statements and related disclosures.

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

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133*, which changes the disclosure requirements for derivative instruments and hedging activities. Expanded disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement will require us to provide the additional disclosures described above.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This Statement is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*, which has not yet occurred. We do not expect the adoption of SFAS 162 to have a material effect on our financial statements or related disclosures.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 18 to the financial statements, to minimize the effect of a downturn in oil and gas prices and to protect our profitability and the economics of our development plans, we enter into crude oil and natural gas hedge contracts from time to time. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in any commodity price increases. In California, we benefit from lower natural gas pricing as we are a consumer of natural gas in our operations and elsewhere we benefit from higher natural gas pricing. We have hedged, and may hedge in the future both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level, some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate in accordance with policy established by our board of directors.

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

The following table summarizes our commodity hedge positions as of December 31, 2008:

Term	Average Barrels Per Day	Floor/Ceiling Prices
Crude Oil Sales (NYMEX WTI) Collars		
Full year 2009	295	\$80.00/\$91.00
Full year 2009	1,000	\$100.00/\$163.60
Full year 2009	1,000	\$100.00/\$150.30
Full year 2009	1,000	\$100.00/\$160.00
Full year 2009	1,000	\$100.00/\$150.00
Full year 2009	1,000	\$100.00/\$157.48
Full year 2010	1,000	\$60.00 / \$80.00
Full year 2010	1,000	\$55.00 / \$76.20
Full year 2010	1,000	\$55.00 / \$77.75
Full year 2010	1,000	\$55.00 / \$77.70
Full year 2010	1,000	\$55.00 / \$83.10
Full year 2010	1,000	\$60.00 / \$75.00
Full year 2010	1,000	\$65.15 / \$75.00
Full year 2010	1,000	\$65.50 / \$78.50
Full year 2010	280	\$80.00 / \$90.00
Full year 2010	1,000	\$100.00/\$161.10
Full year 2010	1,000	\$100.00/\$150.30
Full year 2010	1,000	\$100.00/\$160.00
Full year 2010	1,000	\$100.00/\$150.00
Full year 2010	1,000	\$100.00/\$158.50
Full year 2010	1,000	\$70.00/\$86.00
Full year 2011	270	\$80.00 / \$90.00
Crude Oil Sales (NYMEX WTI) Swaps		Average Price
Full year 2009	240	\$71.50
Full year 2009	1,000	\$70.30
Full year 2009	1,000	\$70.50
1st Quarter 2009	2,000	\$51.70
2nd, 3rd & 4th Quarters 2009	2,000	\$55.00
Full year 2009	1,000	\$54.67
Full year 2009	2,000	\$54.10
Full year 2009	5,000	\$54.39

Term	Average MMBtu Per Day	Average Price
Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
1st Quarter 2009	15,400	\$1.17
2nd Quarter 2009	15,400	\$1.12
3rd Quarter 2009	15,400	\$0.97
4th Quarter 2009	15,400	\$1.05
Full year 2009	2,000	\$1.24
Full year 2009	3,000	\$1.19
Full year 2010	2,000	\$1.05
Full year 2010	3,000	\$1.00
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2009	15,400	\$8.50
Full year 2009	2,000	\$6.15
Full year 2009	3,000	\$6.19
Natural Gas Sales (NYMEX HH) Collars		Floor/Ceiling Prices
Full year 2010	2,000	\$6.00/\$8.60
Full year 2010	3,000	\$6.00/\$8.65

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

From January 1, 2009 to February 25, 2009, we entered into gas collars for 4,000 MMBtu/D with a floor of \$6.50 and ceilings ranging from \$8.75 to \$8.90, for the full year 2010 and E. Texas basis swaps on the same volumes for average prices of \$0.38 and \$0.49. We converted 6,000 Bbl/D oil collars ranging from floors of \$55.00 to \$60.00 and ceilings of \$75.00 to \$83.10 for the full year 2010 for swaps for the same volumes ranging from \$61.00 to \$64.80. We also entered into oil collars for 3,000 Bbl/D for the full year 2011 with a floor of \$55.00 to \$55.20 and a ceiling of \$ 68.65 to \$70.50, an oil swap for 500 Bbl/D for the third quarter of 2009 for \$52.40, an oil swap for 650 Bbl/D for the full year 2010 for \$56.90 and oil swaps for 1,750 Bbl/D for the full year 2011 for average prices from \$56.36 to \$61.80.

The collar strike prices will allow us to protect a significant portion of our future cash flow if 1) oil prices decline below our floor prices which range from \$55.00 to \$100.00 per barrel while still participating in any oil price increase up to the ceiling prices which range from $75.00 to $163.60 per barrel on the volumes indicated above, and if 2) gas prices decline below our floor price of $6.00 per MMBtu while still participating in any gas price increase up to the ceiling prices, which range from $8.60 to $8.65 per MMBtu on the respective volumes. These hedges improve our financial flexibility by locking in significant revenues and cash flow upon a substantial decline in crude oil or natural gas prices, including certain basis differentials. It also allows us to develop our long-lived assets and pursue exploitation opportunities with greater confidence in the projected economic outcomes and allows us to borrow a higher amount under our senior unsecured revolving credit facility.

While we have designated our hedges as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, it is possible that a portion of the hedge related to the movement in the WTI to California heavy crude oil price differential may be determined to be ineffective. Likewise, we may have some ineffectiveness in our natural gas hedges due to the movement of HH pricing as compared to actual sales points. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income (Loss). If the differential were to change significantly, it is possible that our hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to our net income. The marked-to-market values reflect the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participant at the measurement date.

We entered into derivative contracts (natural gas swaps and collar contracts) in March 2006 that did not qualify for hedge accounting under SFAS 133 because the price index for the location in the derivative instrument did not correlate closely with the item being hedged. These contracts were recorded in the first quarter of 2006 at their fair value on the Balance Sheet and we recognized an unrealized net loss of approximately $4.8 million on the Statements of Income under the caption "Commodity derivatives." We entered into natural gas basis swaps on the same volumes and maturity dates as the previous hedges in May 2006 which allowed for these derivatives to be designated as cash flow hedges going forward, causing an unrealized net gain of $5.6 million to be recognized in the second quarter of 2006. The difference of $0.8 million was recorded in other comprehensive income at the date the hedges were designated.

In 2008 we exchanged 10,000 Bbl/D oil collar contracts for calendar 2009 with a floor of $47.50 and a ceiling of $70.00 for swaps with strike prices ranging from $54.10 to $55.00. The collars were exchanged for the swaps on the same day and the collars were dedesignated and the swaps were redesignated in the same day.

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.

At December 31, 2008, Accumulated Other Comprehensive Income, net of income taxes, consisted of $114 million of unrealized gains from our crude oil and natural gas hedges. Deferred net gains recorded in Accumulated Other Comprehensive Income at December 31, 2008 are expected to be reclassified to earnings in the same period as the hedged transaction. The 10,000 Bbl/D oil collars that were exchanged in 2008 for oil swaps were frozen in Accumulated Other Comprehensive Income on the day of conversion and will be reclassified to earning in the same period as the hedged transaction. 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.

	2008	2007	2006
Net reduction of sales of oil and gas revenue due to hedging activities (in millions)	$ 121.5	$ 21.8	$ 15.7
Net reduction of cost of gas due to hedging activities (in millions)	$ -	$ -	$ 1.6
Net reduction in revenue per BOE due to hedging activities	$ 10.41	$ 2.22	$ 1.71

Based on NYMEX futures prices as of December 31, 2008 (WTI $61.47; HH $6.84), we would expect to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	12/31/08 NYMEX Futures	Impact of percent change in futures prices on pretax future cash (payments) and receipts -40%	-20%	+20%	+40%
Average WTI Futures Price (2009 – 2011)	$ 61.47	$ 36.88	$ 49.18	$ 73.77	$ 86.06
Average HH Futures Price (2009)	6.84	4.10	5.47	8.22	9.59
Crude Oil gain/(loss) (in millions)	$ 185.2	$ 353.5	$ 254.0	$ 116.7	$ 29.5
Natural Gas gain/(loss) (in millions)	12.2	34.0	20.8	1.7	(10.6)
Total	$ 197.4	$ 387.5	$ 274.8	$ 118.4	$ 18.9
Net pretax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2009 (WTI $52.88; HH $6.42)	$ 120.5	$ 178.7	$ 142.9	$ 76.8	$ 38.1
2010 (WTI $63.10)	75.8	204.9	131.9	41.6	(18.6)
2011 (WTI $68.44)	1.1	3.9	-	-	(0.6)
Total	$ 197.4	$ 387.5	$ 274.8	$ 118.4	$ 18.9

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued $200 million of 8.25% senior subordinated notes due 2016 in a public offering. Total long-term debt outstanding at December 31, 2008 and 2007 was $1.13 billion and $445 million, respectively. Interest on amounts borrowed under our revolving credit facility is charged at LIBOR plus 1.375% to 2.125%, subject to our interest rate hedges, plus the senior unsecured revolving credit facility's margin through June 30, 2012. Based on year end 2008 credit facility borrowings, a 1% change in interest rates would have a $3.7 million after tax impact on our financial statements.

In June 2006 and July 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility. These interest rate swaps have been designated as cash flow hedges. In 2008, $50 million of these interest rate swaps were extended one year, resulting in a fixed rate of approximately 4.8%. In 2008 we also entered into three year interest rate swaps for a fixed rate of approximately 2.2% on an additional $275 million of our outstanding borrowings under our credit facility for three years beginning on April 15 and September 15, 2009. These interest rate swaps have been designated as cash flow hedges. As of December 31, 2008, we had a total of $575 million of fixed rate positions averaging 4.8% resulting from the $200 million of 8.25% senior subordinated notes and $375 million of interest rate swaps for a fixed rate of approximately 2.2%.

From January 1, 2009 through February 25, 2009, we entered into three year interest rates swaps for a fixed rate of approximately 2.0% on an additional $100 million of our outstanding borrowings under our credit facility for three years beginning on April 15 and December 15, 2009. These interest rate swaps have been designated as cash flow hedges. As a result of these 2009 hedge contracts, we have a total of $675 million of fixed rate positions averaging 4.4%.

Item 8. Financial Statements and Supplementary Data

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 4 to the financial statements, the Company changed the manner in which it accounts for recurring fair value measurements of financial instruments in 2008.

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

Denver, Colorado
February 25, 2009

BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2008 and 2007
(In Thousands, Except Share Information)

ASSETS	2008	2007
Current assets:		
Cash and cash equivalents	$ 240	$ 316
Short-term investments	66	58
Accounts receivable, net of allowance for doubtful accounts of $38,511 and $0, respectively	65,873	117,038
Deferred income taxes	-	28,547
Fair value of derivatives	111,886	2,109
Assets held for sale	-	1,394
Prepaid expenses and other	11,015	11,557
Total current assets	189,080	161,019
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,254,425	1,275,091
Fair value of derivatives	79,696	-
Other assets	19,182	15,996
	$ 2,542,383	$ 1,452,106
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 119,221	$ 90,354
Revenue and royalties payable	34,416	47,181
Accrued liabilities	34,566	21,653
Line of credit	25,300	14,300
Income taxes payable	187	2,591
Deferred income taxes	45,490	-
Fair value of derivatives	1,445	95,290
Total current liabilities	260,625	271,369
Long-term liabilities:		
Deferred income taxes	270,323	128,824
Long-term debt	1,131,800	445,000
Asset retirement obligation	41,967	36,426
Unearned revenue	-	398
Other long-term liabilities	5,921	1,657
Fair value of derivatives	4,203	108,458
	1,454,214	720,763
Commitments and contingencies (Note 14)		
Shareholders' equity:		
Preferred stock, $0.01 par value, 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, $0.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 42,782,365 shares issued and outstanding (42,583,002 in 2007)	427	425
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899) (1,797,784 in 2007)	18	18
Capital in excess of par value	79,653	66,590
Accumulated other comprehensive income (loss)	113,697	(120,704)
Retained earnings	633,749	513,645
Total shareholders' equity	827,544	459,974
	$ 2,542,383	$ 1,452,106

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

BERRY PETROLEUM COMPANY
Statements of Income
Years ended December 31, 2008, 2007 and 2006
(In Thousands, Except Per Share Data)

	2008	2007	2006
REVENUES			
Sales of oil and gas	$ 697,977	$ 467,400	$ 430,497
Sales of electricity	63,525	55,619	52,932
Gas marketing	35,750	-	-
Gain (loss) on sale of assets	(1,297)	54,173	97
Interest and other income, net	5,576	6,265	2,812
	801,531	583,457	486,338
EXPENSES			
Operating costs - oil and gas production	200,098	141,218	117,624
Operating costs - electricity generation	54,891	45,980	48,281
Production taxes	29,898	17,215	14,674
Depreciation, depletion & amortization - oil and gas production	138,237	93,691	67,668
Depreciation, depletion & amortization – electricity generation	2,812	3,568	3,343
Gas marketing	32,072	-	-
General and administrative	55,353	40,210	36,841
Interest	26,209	17,287	10,247
Commodity derivatives	358	-	(736)
Dry hole, abandonment, impairment and exploration	12,316	13,657	12,009
Bad debt expense	38,665	-	-
	590,909	372,826	309,951
Income before income taxes	210,622	210,631	176,387
Provision for income taxes	77,093	80,703	68,444
Net income	$ 133,529	$ 129,928	$ 107,943
Basic net income per share	$ 3.00	$ 2.95	$ 2.46
Diluted net income per share	$ 2.94	$ 2.89	$ 2.41
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	44,485	44,075	43,948
Effect of dilutive securities:			
Stock options	781	604	723
Other	129	227	103
Weighted average number of shares of capital stock used to calculate diluted net income per share	45,395	44,906	44,774

Statements of Comprehensive Income
Years Ended December 31, 2008, 2007 and 2006
(In Thousands)

	2008	2007	2006
Net income	$ 133,529	$ 129,928	$ 107,943
Unrealized gains (losses) on derivatives, net of income taxes of $96,546, ($66,627), and $7,647, respectively	157,522	(99,941)	11,471
Reclassification of realized gains (losses) on derivatives included in net income, net of income taxes of $47,119, ($524) and ($4,712), respectively	76,879	(786)	(7,068)
Comprehensive income	$ 367,930	$ 29,201	$ 112,346

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

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2008, 2007 and 2006
(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity
Balances at January 1, 2006	$ 211	$ 9	$ 56,064	$ 302,306	$ (24,380)	$ 334,210
Two-for one stock split	211	9	(220)	-	-	-
Shares repurchased and retired (600,200 shares)	(6)	-	(18,713)	-	-	(18,719)
Stock-based compensation (498,939 shares)	5	-	9,256	-	-	9,261
Tax impact of stock option exercises	-	-	3,444	-	-	3,444
Deferred director fees - stock compensation	-	-	335	-	-	335
Cash dividends declared - $0.30 per share, including RSU dividend equivalents	-	-	-	(13,177)	-	(13,177)
Change in fair value of derivatives	-	-	-	-	4,403	4,403
Net income	-	-	-	107,943	-	107,943
Balances at December 31, 2006	421	18	50,166	397,072	(19,977)	427,700
Stock-based compensation (484,451 shares)	4	-	12,930	-	-	12,934
Tax impact of stock option exercises	-	-	3,049	-	-	3,049
Deferred director fees - stock compensation	-	-	445	-	-	445
Cash dividends declared - $0.30 per share, including RSU dividend equivalents	-	-	-	(13,292)	-	(13,292)
Cumulative effect of accounting change from adoption of FIN 48	-	-	-	(63)	-	(63)
Change in fair value of derivatives	-	-	-	-	(100,727)	(100,727)
Net income	-	-	-	129,928	-	129,928
Balances at December 31, 2007	425	18	66,590	513,645	(120,704)	459,974
Stock-based compensation (199,363 shares)	2	-	11,684	-	-	11,686
Tax impact of stock option exercises	-	-	938	-	-	938
Deferred director fees - stock compensation	-	-	441	-	-	441
Cash dividends declared - $0.30 per share, including RSU dividend equivalents	-	-	-	(13,425)	-	(13,425)
Change in fair value of derivatives	-	-	-		234,401	234,401
Net income	-	-	-	133,529	-	133,529
Balances at December 31, 2008	$ 427	$ 18	$ 79,653	$ 633,749	$ 113,697	$ 827,544

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

BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2008, 2007 and 2006
(In Thousands)

	2008	2007	2006
Cash flows from operating activities:			
Net income	$ 133,529	$ 129,928	$ 107,943
Depreciation, depletion and amortization	141,049	97,259	71,011
Dry hole and impairment	9,932	12,951	8,253
Commodity derivatives	(108)	574	(109)
Stock-based compensation expense	9,313	8,200	6,436
Deferred income taxes	67,982	62,465	51,666
(Gain) loss on sale of asset	1,297	(54,173)	(97)
Other, net	(756)	3,561	544
Cash paid for abandonment	(4,607)	(1,188)	606
Allowance for bad debt	38,511	-	-
Change in book overdraft	23,984	(9,400)	15,246
(Increase) decrease in current assets other than cash, cash equivalents and short-term investments	10,281	(47,876)	(16,338)
Increase (decrease) in current liabilities other than line of credit	(20,838)	36,578	13,314
Net cash provided by operating activities	409,569	238,879	258,475
Cash flows from investing activities:			
Exploration and development of oil and gas properties	(392,769)	(281,702)	(265,110)
Property acquisitions	(667,996)	(56,247)	(257,840)
Additions to vehicles, drilling rigs and other fixed assets	(4,832)	(3,565)	(21,306)
Capitalized interest	(23,209)	(18,104)	(9,339)
Proceeds from sale of assets	2,037	72,405	4,812
Net cash used in investing activities	(1,086,769)	(287,213)	(548,783)
Cash flows from financing activities:			
Proceeds from issuances on line of credit	404,000	395,150	327,250
Payments on line of credit	(393,000)	(396,850)	(322,750)
Proceeds from issuance of long-term debt	1,708,700	229,300	569,700
Payments on long-term debt	(1,021,900)	(174,300)	(254,700)
Dividends paid	(13,425)	(13,292)	(13,177)
Repurchase of shares	-	-	(18,713)
Proceeds from stock option exercises	2,813	5,178	3,156
Excess tax benefit	938	3,049	3,444
Debt issuance costs	(11,002)	(1)	(5,476)
Net cash provided by financing activities	677,124	48,234	288,734
Net decrease in cash and cash equivalents	(76)	(100)	(1,574)
Cash and cash equivalents at beginning of year	316	416	1,990
Cash and cash equivalents at end of year	$ 240	$ 316	$ 416
Supplemental disclosures of cash flow information:			
Interest paid	$ 38,917	$ 33,945	$ 15,019
Income taxes paid	$ 13,290	$ 6,715	$ 18,148
Supplemental non-cash activity:			
Increase (decrease) in fair value of derivatives:			
Current (net of income taxes of $75,772, ($36,562), and $4,188, respectively)	$ 123,628	$ (54,844)	$ 6,282
Non-current (net of income taxes of $67,893, ($30,589), and ($1,252), respectively)	110,773	(45,883)	(1,879)
Net increase (decrease) to accumulated other comprehensive income (loss)	$ 234,401	$ (100,727)	$ 4,403
Non-cash financing activity: Property acquired for debt	$ -	$ -	$ 54,000

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

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

1. General

We are an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. We have invested in cogeneration facilities which provide steam required for the extraction of heavy oil and which generates electricity for sale.

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

2. Reclassifications and Error Corrections

Certain reclassifications have been made to prior period financial statements to conform them to the current year presentation. Specifically, the change in book overdraft line in the Statements of Cash Flows is classified as an operating activity to reflect the use of these funds in operations, rather than their prior year classification as a financing activity.

In March 2008, we determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. We concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, the error was corrected during the first quarter of 2008, with the effect of increasing our sales of oil and gas by $10.5 million and reducing our royalties payable.

3. 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, 2008 and 2007 is $31.8 million and $7.8 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

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

Accounts receivable - Trade accounts receivable are recorded at the invoiced amount. We do not have any off-balance-sheet credit exposure related to our customers. We assess credit risk and allowance for doubtful accounts on a customer specific basis. As of December 31, 2008 and 2007, we have an allowance for doubtful accounts of $38.5 million and $0, respectively. The 2008 amount represents the Company's November and December 2008 sales to Big West of California (BWOC). In December 2008, Flying J, Inc., and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's production. We have entered into various short-term agreements with other companies to sell our California oil production. Pricing and volumes under these agreements vary with prices ranging from just above the posted price for San Joaquin heavy oil to the posted price less a discount. In January 2009, our California crude oil daily production was, on average, near levels achieved prior to BWOC's Chapter 11 filing. BWOC is evaluating several options, including a sale of the Bakersfield, California refinery. We recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of the $38.5 million due from BWOC, $12.4 million represents December crude oil sales by the Company and represents an administrative claim under the bankruptcy proceedings and $26.1 million represents November crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract for any amounts received by us under our short-term contracts which are less than what we would have otherwise received from BWOC had they been able to accept our production. We have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that our claim is not fully collectible from BWOC. While we believe that we may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected nor as to whether BWOC will assume or reject our contract.

Income taxes - We compute income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes* as interpreted by FIN 48, *Accounting for Uncertainty in Income Taxes*. SFAS No. 109 requires an asset and liability approach which results in the recognition of deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. A valuation allowance is recognized if it is determined that deferred tax assets may not be fully utilized in future periods. FIN 48 also requires that amounts recognized in the Balance Sheet related to uncertain tax positions be classified as a current or noncurrent liability, based upon the expected timing of the payment to a taxing authority.

Derivatives - To minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, from time to time we enter into crude oil and natural gas hedge contracts. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities on the Balance Sheet. Settlements are recognized on the Statements of Income under the caption "Sales of oil and gas." The accounting for changes in the fair value of a derivative depends on the intended use of the derivative, and the resulting designation is generally established at the inception of a derivative contract. For derivative contracts that do not qualify for hedge accounting under SFAS No. 133, the contracts are recorded at fair value on the Balance Sheet with the corresponding unrealized gain or loss on the Statements of Income under the caption "Commodity derivatives." For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value, to the extent effective, are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. The hedging relationship between the hedging instruments and hedged items, such as oil and gas, must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. We measure hedge effectiveness at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, or in the case of options based on the change in intrinsic value. A regression analysis is used to determine whether the relationship is considered to be highly effective retrospectively and prospectively. Actual effectiveness of the hedge will be calculated against the underlying cumulatively using the dollar offset method at the end of each quarter. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss, such as time value for option contracts, will be recognized immediately in the Statements of Income. Gains and losses on hedging instruments and adjustments of the carrying amounts of hedged items are included in revenues for hedges related to our crude oil and natural gas sales and in operating expenses for hedges related to our natural gas consumption. The resulting cash flows are reported as cash flows from operating activities. See Note 18 - 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 an asset for sale. Upon designation as held for sale, the carrying value of the asset is recorded at the lower of the carrying value or its estimated fair value, less costs to sell. Once an asset is determined to be "held for sale", we no longer record DD&A on the property. We anticipate that we will dispose of certain properties or assets over time. The assets most likely for disposition will be those that do not fit or complement our strategic growth plan, that are not contributing satisfactory economic returns given the profile of the assets, or that we believe the development potential will not be meaningful to our company as a whole. Proceeds from these sales will contribute to the funding of our capital program. Net oil and gas properties and equipment classified as held for sale is zero and $1.4 million as of December 31, 2008 and 2007, respectively, in accordance with SFAS No. 144.

Leases - We entered into two separate three year lease agreements on two company owned drilling rigs. Each agreement has a three year purchase option in favor of the lessee. The agreements were signed in 2005 and 2006 and are accounted for as direct financing leases as defined by SFAS No. 13, *Accounting for Leases,* and included in other long term assets on the Balance Sheet. We routinely enter into noncancelable lease agreements for premises and equipment used in the normal course of business. In addition to minimum rental payments, certain of these leases require additional payments to reimburse the lessors for operating expenses such as real estate taxes, maintenance, utilities and insurance. Rental expense is recorded on a straight-line basis. Both of these lease agreements were terminated as of December 31, 2008.

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

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

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

<u>Asset retirement obligations (ARO)</u> - 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 use our historical cost to abandon wells and facilities to provide evidence of our future cost to adandon these assets. 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.

<u>Accrued liabilities</u> - Accrued liabilities consist primarily of Accrued property taxes, Accrued interest and Accrued payroll costs. Accrued property taxes were $13.5 million and $8.5 million as of December 31, 2008 and 2007, respectively. Accrued interest was $8.4 million and $3.3 million as of December 31, 2008 and 2007, respectively. Accrued payroll costs were $8.4 million and $7.1 million as of December 31, 2008 and 2007, respectively.

<u>Revenue recognition</u> - Revenues associated with sales of crude oil, natural gas, electricity and natural gas marketing are recognized when title passes to the customer, net of royalties, discounts and allowances, as applicable. The electricity and natural gas we produce and use in our operations are not included in revenues. Revenues from crude oil and natural gas production from properties in which we have an interest with other producers are recognized on the basis of our net working interest (entitlement method). Revenues are derived from gas marketing sales which represent excess capacity on the Rockies Express pipeline which we use to market natural gas for our working interest partners.

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

<u>Cogeneration operations</u> - 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, 2008, 2007 and 2006 was $5.8 million, $5.0 million and $5.3 million, respectively.

<u>Shipping and handling costs</u> - Shipping and handling costs, consisting primarily of natural gas transportation costs, are included in either "Operating costs - oil and gas production" or "Operating costs - electricity generation," as applicable. Natural gas transportation costs included in Operating costs - oil and gas production were $9.5 million, $1.2 million and $0 for 2008, 2007 and 2006, respectively. Natural gas transportation costs included in Operating costs - electricity generation were $7.2 million, $6.7 million and $6.8 million for 2008, 2007 and 2006, respectively. Additionally, the transportation costs in Uinta were $0.2 million, $1.4 million and $1.4 million in 2008, 2007 and 2006, respectively.

<u>Production taxes</u> - Consist primarily of severance, production and ad valorem taxes.

<u>Stock-based compensation</u> - We adopted SFAS No. 123(R) beginning January 1, 2006. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation* effective January 1, 2004. The implementation of FAS123(R) did not have a material impact on us. The modified prospective method was selected as described in SFAS 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. Under this method, we recognize stock option compensation expense as if we had applied the fair value method to account for unvested stock options from the original effective date. We recognize stock option compensation expense from the date of grant to the vesting date.

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

Net income per share - Basic net income per share is computed by dividing income available to shareholders (the numerator) by the weighted average number of shares of capital stock outstanding (the denominator). Our Class B Stock is included in the denominator of basic and diluted net income. The computation of diluted net income per share is similar to the computation of basic net income per share except that the denominator is increased to include the dilutive effect of the additional common shares that would have been outstanding if all convertible securities had been converted to common shares during the period. Nonqualified stock options totaling 340,000, 855,000, and 499,000 were excluded from the calculation of diluted net income per common share for 2008, 2007 and 2006, respectively, because they were antidilutive. The assumed proceeds in the treasury stock calculation include proceeds received for the grant price and the tax windfall/shortfall amounts recognized in the financial statements.

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

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

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

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

Recent accounting developments - In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. This interpretation requires that realization of an uncertain income tax position must be "more likely than not" (i.e. greater than 50% likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, this interpretation prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. This interpretation also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. We adopted this interpretation in the first quarter of 2007. See Note 12.

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. We adopted this Statement in 2008 and increased our disclosures accordingly. SFAS No. 157-2 addresses the same topic for nonfinancial assets and liabilities and will become effective for our fiscal year beginning January 1, 2009. We do not believe that the implementation of SFAS 157-2 will have a material impact on our financial statements.

In April 2007, the FASB issued a FASB Staff Position to amend FASB Interpretation 39, *Offsetting of Amounts Related to Certain Contracts*. FIN 39-1 states that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with paragraph 10 of Interpretation 39. FIN 39-1 became effective for our fiscal year beginning January 1, 2008 and did not have any effect on our financial statements, as we do not post collateral under our hedging agreements.

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

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133*, which changes the disclosure requirements for derivative instruments and hedging activities. Expanded disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement will require us to provide the additional disclosures described above in the first quarter of 2009.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This Statement became effective on November 13, 2008.

In September 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Positions (FSP) No. 133-1 and FIN 45-4 to amend FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to require disclosures by sellers of credit derivatives, including credit derivatives embedded in a hybrid instrument. This FSP also amends FASB Interpretation No.45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*, to require an additional disclosure about the current status of the payment/performance risk of a guarantee. Further, this FSP clarifies the FASB's intent about the effective date of FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*. This FSP was adopted in 2008 and did not have a material effect on our financial statements and related disclosures.

In February 2009, the SEC issued its final rule on *Modernization of Oil and Gas Reporting* (the Final Rule), which revises the disclosures required by oil and gas companies. In addition to changing the definition and disclosure requirements for oil and gas reserves, the Final Rule changes the requirements for determining quantities of oil and gas reserves. The Final Rule also changes certain accounting requirements under the full cost method of accounting for oil and gas activities. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves, with a view to helping investors evaluate their investments in oil and gas companies. The amendments are designed to modernize the requirements for the determination of oil and gas reserves, aligning them with current practices and updating them for changes in technology. The Final Rule applies to registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. This rule will require us to provide the additional disclosures described above in our 10-K for our fiscal year ending December 31, 2009. We are still evaluating the impact the Final Rule will have on our financial statements but we may increase the amount of proved, undeveloped reserves reported from technology advances and we may disclose probable and possible reserves.

General - The price sensitive royalty that burdens our Formax property in the South Midway Sunset field has changed. We previously paid a royalty equal to 75% of the amount of the heavy oil posted above a price of $16.11. This price escalates at 2% annually. Effective January 1, 2008, the royalty rate is reduced from 75% to 53% as long as we maintain a minimum steam injection level, which we expect to meet, that reduces over time. Current net production from this property is approximately 2,300 Bbl/D.

4. Fair Value Measurement

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. We adopted this Statement as of January 1, 2008.

Determination of fair value

We have established and documented a process for determining fair values. Fair value is based upon quoted market prices, where available. We have various controls in place to ensure that valuations are appropriate. These controls include: identification of the inputs to the fair value methodology through review of counterparty statements and other supporting documentation, determination of the validity of the source of the inputs, corroboration of the original source of inputs through access to multiple quotes, if available, or other information and monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

Valuation hierarchy

SFAS 157 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

- Level 1 - inputs to the valuation methodology that are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology that include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology that are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement.

Our oil swaps, natural gas swaps and interest rate swaps are valued using the counterparties' mark-to-market statements which are validated by our internally developed models and are classified within Level 2 of the valuation hierarchy. The observable inputs include underlying commodity and interest rate levels and quoted prices of these instruments on actively traded markets. Derivatives that are valued based upon models with significant unobservable market inputs (primarily volatility), and that are normally traded less actively are classified within Level 3 of the valuation hierarchy. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps.

Assets and liabilities measured at fair value on a recurring basis

December 31, 2008 (in millions)	Total carrying value on the Balance Sheet	Level 2	Level 3
Commodity derivative asset	198.4	25.9	172.5
Interest rate swaps liability	(12.5)	(12.5)	-
Total assets at fair value	185.9	13.4	172.5

Changes in Level 3 fair value measurements

The table below includes a rollforward of the Balance Sheet amounts (including the change in fair value) for financial instruments classified by us within Level 3 of the valuation hierarchy. When a determination is made to classify a financial instrument within Level 3 of the valuation hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources).

(in millions)	Three months ended December 31, 2008	Twelve months ended December 31, 2008
Fair value liability, beginning of period	$ (208.9)	$(194.3)
Total realized and unrealized gains and (losses) included in sales of oil and gas	227.1	196.0
Purchases, sales and settlements, net	154.3	170.8
Transfers in and/or out of Level 3	-	-
Fair value asset, December 31, 2008	172.5	172.5
Total unrealized gains and (losses) included in income related to financial assets and liabilities still on the condensed balance sheet at December 31, 2008	$ -	$-

In February of 2007, the FASB issued SFAS 159, which is effective for fiscal years beginning after November 15, 2007. SFAS 159 provides an option to elect fair value as an alternative measurement for selected financial assets and financial liabilities not previously carried at fair value. We adopted this statement at January 1, 2008, but did not elect fair value as an alternative for any financial assets or liabilities.

Cash equivalents consist principally of bank deposits. Cash and equivalents of $0.2 million and $0.3 million at December 31, 2008 and 2007, respectively, are stated at cost.

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. We use available marketing data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with SFAS No. 107, "Disclosures about Fair Value of Financial Instruments" and does not impact our financial position, results of operations or cash flows. Our short-term investments available for sale at December 31, 2008 and 2007 consist of United States treasury notes that mature in less than one year. For the three years ended December 31, 2008, realized and unrealized gains and losses of our short-term investments were insignificant to the financial statements. The cost of our long-term senior subordinated notes is $200 million and the fair value is approximately $116 million. The cost and the fair value of our senior secured credit facilities is approximately $957 million.

5. Concentration of Credit Risks

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

On November 21, 2005, we entered into a crude oil sales contract with BWOC for substantially all of our California production for deliveries beginning February 1, 2006. In December 2008, Flying J, Inc., and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's production. We have entered into various short-term agreements with other companies to sell our California oil production. Pricing and volumes under these agreements vary with prices ranging from just above the posted price for San Joaquin heavy oil to the posted price less a discount. In January 2009, our California crude oil daily production was, on average, near levels achieved prior to BWOC's Chapter 11 filing. BWOC is evaluating several options, including a sale of the Bakersfield, California refinery. We recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of the $38.5 million due from BWOC, $12.4 million represents December 2008 crude oil sales by the Company and represents an administrative claim under the bankruptcy proceedings and $26.1 million represents November 2008 crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract for any amounts received by us under our short-term contracts which are less than what we would have otherwise received from BWOC had they been able to accept our production. We have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that our claim is not fully collectible from BWOC. While we believe that we may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected nor as to whether BWOC will assume or reject our contract.

On February 27, 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D on July 1, 2007. After partial completion of its refinery expansion in Salt Lake City in March 2008, the refiner increased its total purchase capacity to 5,000 Bbl/D. This contract is in effect through June 30, 2013. This contract is our only sales contract for our Uinta oil.

During 2008, the Company experienced two credit losses related to its oil and natural gas sales. Included in bad debt expense is $0.2 million related to the bankruptcy of SemGroup and $38.5 million related to BWOC as described above. During the two years 2006 and 2007, we did not have any credit losses on the sale of oil, natural gas, natural gas liquids or hedging contracts.

We place our temporary cash investments with high quality financial institutions and limit the amount of credit exposure to any one financial institution. For the three years ended December 31, 2008, we have not incurred losses related to these investments.

As of December 31, 2008, $177 million, of the approximate net value of the Company's hedging positions of approximately $186 million, can be attributed to one of three counterparties. While a significant portion of our hedges are with a small number of counterparties, we monitor each counterparty's credit rating and CDS rate and as of December 31, 2008 each of our hedge counterparties maintained a rating of AA-(S&P)/Aa2(Moody's) or better. Neither we nor our counterparties are required to post collateral under our hedging contracts.

The following summarizes the accounts receivable balances at December 31, 2008 and 2007 and sales activity with significant customers for each of the years ended December 31, 2008, 2007 and 2006 (in thousands). We do not believe that the loss of any one customer would impact the marketability, but it may impact the profitability of our crude oil, gas, natural gas liquids or electricity sold. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the crude oil sales customer could impact the marketability of a portion of our Utah crude oil volumes.

	Accounts Receivable As of December 31,		Sales before hedging and royalties For the Year Ended December 31,		
Customer	2008	2007	2008	2007	2006
Oil & Gas Sales:					
A	$ 4,082	$ 5,347	$ 107,414	$ 39,791	$ -
B	-	-	3,795	20,239	75,597
C	4	5,793	17,734	28,170	10,458
D	38,787	44,450	582,885	404,038	305,587
E	5,785	-	32,431	-	-
	$ 48,658	$ 55,590	$ 744,259	$ 492,238	$ 391,642
Electricity Sales:					
F	$ 1,799	$ 1,979	$ 30,975	$ 26,033	$ 24,335
G	2,227	2,573	34,553	29,470	28,597
	$ 4,026	$ 4,552	$ 65,528	$ 55,503	$ 52,932

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. Accounts receivable amounts will not agree to the Balance Sheet due primarily to the Allowance for doubtful accounts, which is netted in Accounts receivable on the Balance Sheet.

As of December 31, 2008 we have an allowance for doubtful accounts of $38.5 million which represents the Company's November and December 2008 sales to Big West of California (BWOC). While the Company believes that it may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided the Company with any data from which to make a conclusion that any amounts will be collected. We did not have an allowance for doubtful accounts for the year ended December 31, 2007.

6. Oil and Gas Properties, Buildings and Equipment

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

Oil and gas:	2008	2007
Proved properties:		
Producing properties, including intangible drilling costs	$ 1,820,609	$ 869,176
Lease and well equipment (1)	663,610	448,100
	2,484,219	1,317,276
Unproved properties		
Properties, including intangible drilling costs	255,412	285,823
	2,739,631	1,603,099
Less accumulated depreciation, depletion and amortization	509,277	350,604
	2,230,354	1,252,495
Commercial and other:		
Land	810	810
Drilling rigs and equipment	13,166	12,443
Buildings and improvements	6,274	5,407
Machinery and equipment	22,767	18,525
	43,017	37,185
Less accumulated depreciation	18,946	14,589
	24,071	22,596
	$ 2,254,425	$ 1,275,091

(1) *Includes cogeneration facility costs.*

On July 15, 2008, the Company acquired certain interests in natural gas producing properties on 4,500 net acres in Limestone and Harrison Counties in East Texas for $668 million cash (E. Texas Acquisition) including an initial purchase price of $622 million, and post closing adjustments of $46 million.

In February 2006, we closed on an agreement with a private seller to acquire a 50% working interest in natural gas assets in Piceance 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. The 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 Piceance of western Colorado. We estimate we will pay up to $153 million to fund the drilling of 90 natural gas wells on the joint venture partner's acreage. The maximum amount of cost charged to us will not exceed $1.7 million per well. If any wells are drilled for less than $1.7 million, the excess will be returned to us. In exchange for our payments of up to $153 million, we will earn a 5% working interest (4% net revenue interest) on each of the 90 wellbores and a net working interest of 95% (79% net revenue interest) in 4,300 gross acres located elsewhere on the property. The costs of drilling and development on the 4,300 gross acres will be shared by the partners in relation to the working interests. The $153 million payment was allocated to unproved properties based on the fair value of the 5% and 95% working interests.

In July 2006, we paid $51 million, the first installment of the total $153 million, and thereby earned the assignment of the 4,300 gross acres. In November 2006, we paid the second installment of approximately $48 million. We paid the third and final installment of approximately $54 million in May 2007. Prior to February 2011, we are required to drill 120 wells, bearing 95% of the cost, on our 4,300 gross acres and if not met, then we are required to pay $0.2 million for each well less than 120 drilled. Additionally, if we have not drilled at least one well by mid-2011 in each 160 acre tract within the 4,300 gross acres, then that specific undrilled 160 acre tract shall be reassigned to the joint venture partner. As of the date of the agreement there were no operating activities from these gas assets.

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):

	2008	2007	2006
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ -	$ 6,826	$ 89
Capitalized exploratory well costs that have been capitalized for a period greater than one year	-	-	-
Balance at December 31	$ -	$ 6,826	$ 89
Number of projects that have exploratory well costs that have been capitalized for a period of greater than one year	-	-	-

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

	2008	2007	2006
Beginning balance at January 1	$ 6,826	$ 89	$ 6,037
Additions to capitalized exploratory well costs pending the determination of proved reserves	-	6,826	6,682
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(6,826)	-	(4,377)
Capitalized exploratory well costs charged to expense	-	(89)	(8,253)
Ending balance at December 31	$ -	$ 6,826	$ 89

Dry hole, abandonment and impairment and asset sales

In 2008 we had dry hole, abandonment and impairment charges of $12.3 million consisting primarily of $7.3 million for technical difficulties that were encountered on five wells in Piceance before reaching total depth. These holes were abandoned in favor of drilling to the same bottom hole location by drilling new wells. We incurred exploration costs of $2.4 million in 2008 compared to $0.7 million and $3.8 million in 2007 and 2006, respectively. These costs consist primarily of geological and geophysical costs in DJ. Due to the release of our rigs we performed an impairment test which resulted in $2.6 million of impairment costs resulting from the impairment of one rig. Additionally, we performed an impairment test of our oil and gas assets at December 31, 2008 in accordance with SFAS 144 and determined that no impairment was necessary.

In 2007 we had dry hole, abandonment, impairment and exploration charges of $13.7 million that consisted primarily of a $4.6 million writedown on a portion of our Tri-State acreage in connection with the current and pending sale of these properties, a $3.3 million impairment of our Coyote Flats prospect to reflect its fair value in conjunction with the preparation of our year end reserve estimates, a $2.9 million writedown of our Bakken properties which were sold in September 2007, geological and geophysical costs of $0.7 million and other dry hole charges of $2.2 million.

In 2006, there was $8.3 million of dry hole, abandonment and impairment charges that consisted primarily of two Coyote Flats, Utah wells for $5.2 million, our 25% share in an exploration well located in the Lake Canyon project area of Uinta drilled for approximately $1.6 million net to our interest and four wells in Bakken and four wells in DJ for $1.5 million.

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

7. Debt Obligations

Short-term lines of credit

In 2005, we completed an 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 and are subject to the borrowing base under the Company's senior credit facility. The Line of Credit may be terminated at any time upon written notice by either us or the lender. In conjunction with the amendment to our senior secured credit facility, on July 15, 2008, the Line of Credit was secured by our assets. At December 31, 2008 and 2007, the outstanding balance under this Line of Credit was $25.3 million and $14.3 million, respectively. 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, 2008 and 2007 was 1.4% and 5.7%, respectively. Covenants under this agreement match the covenants under our senior secured revolving credit facility.

In July, 2008, we completed a $100 million senior unsecured credit facility that was to mature on December 31, 2008. We terminated this credit facility without penalty in October 2008.

Senior Secured Revolving Credit Facility

On July 15, 2008, we entered into a five year amended and restated credit agreement (the Agreement) with Wells Fargo Bank, N.A. as administrative agent and other lenders. This agreement was amended on October 17, 2008, as noted below. The July 15, 2008 Agreement amended and restated the Company's previous credit agreement dated as of April 28, 2006. The Agreement is a revolving credit facility for up to $1.5 billion with a borrowing base of $1.0 billion. The outstanding Line of Credit reduces our borrowing capacity available under the Agreement. The borrowing base under the April 28, 2006 agreement was $650 million. Interest on amounts borrowed under this debt was charged at LIBOR plus a margin of 1.125% to 1.875% or the prime rate, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. An annual commitment fee of .25% to .375% was charged on the unused portion of the credit facility.

On October 17, 2008, we further amended our $1.5 billion credit facility with the Company's syndicate of banks which increased our borrowing base from $1.0 billion to $1.25 billion with commitments of $1.08 billion and a new maturity date of July 15, 2012. Commitments were increased during the fourth quarter of 2008 with the addition of $130 million in commitments bringing the total commitments under the facility to $1.21 billion from 19 banks. The amendment includes an accordion feature which allows the Company to increase borrowing commitments to $1.25 billion without further bank approval, and modifies the annual commitment fee and interest rate margins. Interest on amounts borrowed under the facility is charged at LIBOR or the prime rate plus a margin. The LIBOR and prime rate margins range between 1.375% and 2.125% based on the ratio of credit outstanding to the borrowing base. Additionally, an annual commitment fee of .30% to .50% is charged on the unused portion of the credit facility. The deferred costs of approximately $10.8 million associated with the issuance of this credit facility and $0.6 million associated with the issuance of the previous credit facility are being amortized over the four year life of the Agreement. The total deferred costs under this facility and the previous facility were $10.6 million as of December 31, 2008. A charge of $0.1 million was recorded on the income statement as a loss on debt extinguishment during the third quarter of 2008 related to parties who reduced their commitment or chose not to participate in the Agreement.

The total outstanding debt at December 31, 2008 under the Agreement and the Line of Credit was $932 million and $25 million, respectively, and $8 million in letters of credit have been issued under the facility, leaving $245 million in borrowing capacity available under the Agreement. The maximum amount available is subject to semi-annual redeterminations of the borrowing base, based on the value of our proved oil and gas reserves, in April and October of each year in accordance with the lender's customary procedures and practices. Both we and the banks have the bilateral right to one additional redetermination each year.

See Note 21 related to changes in the terms of our Senior secured credit facility in February 2009.

Senior Subordinated 8.25% NotesDue 2016

In 2006, we issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Notes). Interest on the Notes is paid semiannually in May and November of each year. The deferred costs of approximately $5 million associated with the issuance of this debt are being amortized over the ten year life of the Notes and the remaining balance as of December 31, 2008 was $4 million. 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 to finance the November 2006 installment under the joint venture agreement to develop properties in Piceance. 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.

Financial Covenants

The senior secured revolving credit facility contains restrictive covenants which, among other things, require us to maintain a debt to EBITDA ratio of not greater than 3.5 to 1.0 and a minimum current ratio, as defined, of 1.0. The non-cash financial statement impact of hedging is excluded from the calculation of both ratios and all of the availability under the senior credit facility is added to current assets when computing the current ratio. The $200 million Notes are subordinated to our credit facility and line of credit indebtedness. Under the Notes, as long as the interest coverage ratio (as defined) is greater than 2.5 times, we may incur additional debt. Our covenant ratios for the two years ended December 31, 2008, were as follows:

	2008	2007
Current Ratio (Not less than 1.0)	1.2	2.5
EBITDA To Total Funded Debt Ratio (Not greater than 3.5)	2.7	1.6
Interest Coverage Ratio (Not less than 2.5)	8.4	9.3

We were in compliance with all such covenants as of December 31, 2008 and 2007.

Interest Rates and Interest Rate Hedges

Additionally, in 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 beginning on September 29, 2006. In 2008, the term on $50 million of these swaps was extended by one year. These interest rate swaps have been designated as cash flow hedges. In 2008, $50 million of these interest rate swaps were extended one year, resulting in a fixed rate of approximately 4.8%.

In 2008 we entered into three year interest rate swaps totaling $275 million for a fixed rate averaging approximately 2.2% on an additional $275 million of our outstanding borrowings under our credit facility for three years beginning on April and September 15, 2009. These interest rate swaps have been designated as cash flow hedges.

As of December 31, 2008, we had a total of $575 million of fixed rate positions averaging 4.8% resulting from the $200 million of 8.25% senior subordinated notes and $375 million of interest rate swaps for a fixed rate of approximately 2.2%.

The weighted average interest rate on total outstanding borrowings at December 31, 2008 and 2007 was 4.9% and 5.7%, respectively, excluding the effect of interest rate hedges.

8. Shareholders' Equity

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

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital Stock," are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $0.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Common Stock at the option of the holder.

In June 2005, we announced that our Board of Directors authorized a share repurchase program for up to an aggregate of $50 million of our outstanding Class A Common Stock. From June 2005 through December 31, 2007, we repurchased 818,000 shares in the open market for approximately $25 million. Our repurchase plan expired and no shares were repurchased in 2007.

Dividends

Our regular annual dividend is currently $0.30 per share, payable quarterly in March, June, September and December. We paid a special dividend of $0.02 per share on September 29, 2006 and increased our regular quarterly dividend by 15%, from $0.065 to $0.075 per share beginning with the September 2006 dividend.

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

Shareholder Rights Plan

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

The Rights will expire on December 8, 2009 or may be redeemed by us at $0.005 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.

9. Asset Retirement Obligations (AROs)

Inherent in the fair value calculation of AROs are numerous assumptions and judgments including: the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. In 2007, we reassessed our estimate as costs increased due to demand for these services, resulting in an increase in the ARO balance at year end. As of December 31, 2008, we did not have any asset retirement obligations for which no liability has been accrued.

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

	2008	2007
Beginning balance at January 1	$ 36,426	$ 26,135
Liabilities incurred	4,686	4,191
Liabilities settled	(4,607)	(2,121)
Revisions in estimated liabilities	2,006	5,779
Accretion expense	3,456	2,442
Ending balance at December 31	$ 41,967	$ 36,426

10. Bad Debt Expense

Of the $38.7 million recorded in bad debt expense for the year ended December 31, 2008, $38.5 million relates to the allowance for bad debt taken for the bankruptcy of BWOC with the remainder due to the bankruptcy of SemCrude earlier in 2008.

In December 2008, Flying J, Inc., and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's production. We have entered into various short-term agreements with other companies to sell our California oil production. Pricing and volumes under these agreements vary with prices ranging from just above the posted price for San Joaquin heavy oil to the posted price less a discount. In January 2009, our California crude oil daily production was, on average, near levels achieved prior to BWOC's Chapter 11 filing. BWOC is evaluating several options, including a sale of the Bakersfield, California refinery. We recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of the $38.5 million due from BWOC, $12.4 million represents December crude oil sales by the Company and represents an administrative claim under the bankruptcy proceedings and $26.1 million represents November crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract for any amounts received by us under our short-term contracts which are less than what we would have otherwise received from BWOC had they been able to accept our production. We have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that our claim is not fully collectible from BWOC. While we believe that we may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected nor as to whether BWOC will assume or reject our contract.

11. Pro Forma Results

On July 15, 2008, the Company acquired certain interests in natural gas producing properties on 4,500 net acres in Limestone and Harrison Counties in East Texas for $668 million cash (E. Texas Acquisition) including an initial purchase price of $622 million and normal post closing adjustments of $46 million.

The unaudited pro forma results presented below for the years ended December 31, 2008 and 2007 have been prepared to give effect to the E. Texas Acquisition on the Company's results of operations under the purchase method of accounting as if it had been consummated at the beginning of each of the periods presented. The unaudited pro forma results do not purport to represent the results of operations that actually would have occurred on such date or to project the Company's results of operations for any future date or period:

		Year Ended December 31, 2008		Year Ended December 31, 2007
Pro forma revenue	$	854,237	$	616,835
Pro forma income from operations	$	217,398	$	164,447
Pro forma net income	$	138,432	$	105,657
Pro forma basic earnings per share	$	3.11	$	2.40
Pro forma diluted earnings per share	$	3.05	$	2.36

The following is a calculation and allocation of purchase price to the E. Texas Acquisition assets and liabilities based on their relative fair values, as determined by the valuation of proved reserves and related assets as of the acquisition date:

		As of December 31, 2008	
Purchase price (in thousands):			
Original purchase price	$	622,356	
Closing adjustments for property costs, and operating expenses in excess of revenues between the effective date and closing date		45,506	
Total purchase price allocation	$	667,862	
Allocation of purchase price (in thousands):			
Oil and natural gas properties	$	651,659	(i)
Pipeline		17,277	
Tax receivable		1,476	
Total assets acquired		670,412	
Current liabilities		(1,195)	(ii)
Asset retirement obligation		(1,355)	
Net assets acquired	$	667,862	

(i) Determined by reserve analysis.
(ii) Accrual for royalties payable.

12. Income Taxes

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

	2008	2007	2006
Current:			
Federal	$ 3,280	$ 12,939	$ 12,231
State	5,795	5,299	4,547
	9,075	18,238	16,778
Deferred:			
Federal	62,412	53,321	44,205
State	5,606	9,144	7,461
	68,018	62,465	51,666
Total	$ 77,093	$ 80,703	$ 68,444

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

	2008	2007
Deferred tax asset:		
Federal benefit of state taxes	$ 11,082	$ 8,391
Credit carryforwards	33,636	33,588
Stock option costs	9,089	6,716
Derivatives	2,282	81,042
Other, net	4,312	3,010
	60,401	132,747
Deferred tax liability:		
Depreciation and depletion	(303,413)	(232,451)
Derivatives	(72,801)	(573)
	(376,214)	(233,024)
Net deferred tax liability	$ (315,813)	$ (100,277)

At December 31, 2008, our net deferred tax assets and liabilities were recorded as a current liability of $45.5 million and a long-term liability of $270.4 million. At December 31, 2007, our net deferred tax assets and liabilities were recorded as a current asset of $28.5 million and a long-term liability of $128.8 million.

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

	2008	2007	2006
Tax computed at statutory federal rate	35%	35%	35%
State income taxes, net of federal benefit	4	5	5
Tax credits		-	-
Other	(2)	(2)	(1)
Effective tax rate	37%	38%	39%

We have approximately $24 million of federal and $17 million of state (California) EOR tax credit carryforwards available to reduce future income taxes. The EOR credits will begin to expire, if unused, in 2024 and 2015 for federal and California purposes, respectively.

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

As of December 31, 2008, we had a gross liability for uncertain tax benefits of $12 million of which $10 million, if recognized, would affect the effective tax rate. We recognize potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. We had accrued approximately $1.2 million and $1.1 million of interest related to our uncertain tax positions as of December 31, 2008 and 2007, respectively.

We anticipate the balance of our unrecognized tax benefits could be reduced during the next 12 months as the IRS finalizes its examination, however, we cannot reasonably estimate the impact of the examination at this time.

For the year ended December 31, 2008 we recognized a net benefit of approximately $1.6 million to the Statements of Income due to the closure of certain federal and state tax years, offset by additional FIN 48 accruals net of interest expense of approximately $1.9 million.

For the year ended December 31, 2007 we recognized a net benefit of approximately $0.6 million to the Statements of Income due to the closure of certain federal and state tax years, offset by additional FIN 48 accruals net of interest expense of approximately $0.2 million.

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

		2008		2007
Unrecognized tax benefits at January 1	$	12.0	$	14.6
Increases for positions taken in current year		1.2		0.5
Increases for positions taken in a prior year		0.3		(.3)
Decreases for settlements with taxing authorities		-		-
Decreases for lapses in the applicable statute of limitations		(1.5)		(2.8)
Unrecognized tax benefits at December 31	$	12.0	$	12.0

As of December 31, 2008, we remain subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction:	Tax Years Subject to Exam:
Federal	2005 – 2007
California	2004 – 2007
Colorado	2004 – 2007
Utah	2005 – 2007

13. Leases Receivable

As of December 31, 2008, all of our rig leases had either expired or were terminated and the leasee did not exercise the bargain purchase option under the lease. The $5.8 million in lease receivable was capitalized under property plant and equipment as of December 31, 2008.

We entered into two separate three year lease agreements on two company owned drilling rigs. Each agreement has a three year purchase option in favor of the lessee. The agreements were signed in 2005 and 2006, respectively. The total net investment in these rigs is approximately $8.8 million at December 31, 2007. Both agreements are accounted for as direct financing leases as defined by SFAS No. 13, *Accounting for Leases*. Net investment in both leases are included in the Balance Sheet as other assets and as of December 31, 2007 are as follows (in thousands):

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

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

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

14. Commitments and Contingencies

We have no accrued environmental liabilities for our sites, including sites in which governmental agencies have designated us as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in substantial costs incurred. We are involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of our business. In the opinion of management, the resolution of these matters will not have a material effect on our financial position, or on the results of our operations or liquidity.

During the California energy crisis in 2000 and 2001, we had electricity sales contracts with various utilities and a portion of the electricity prices paid to us under such contracts from December 2000 to March 27, 2001 has been under a degree of legal challenge since that time. It is possible that we may have a liability pending the final outcome of the CPUC proceedings on the matter. There are ongoing proceedings before the CPUC in which Edison and PG&E are seeking credit against future payments they are to make for electricity purchases based on retroactive adjustment to pricing under contracts with us. Whether or not retroactive adjustments will be ordered, how such adjustments would be calculated and what period they would cover are too uncertain to estimate at this time.

Our contractual obligations not included in our Balance Sheet as of December 31, 2008 (except Long-term debt and Abandonment obligations) are as follows (in thousands):

	Total	2009	2010	2011	2012	2013	Thereafter
Long-term debt and interest	$ 1,471,383	$ 82,211	$ 56,558	$ 56,558	$ 56,558	$ 969,998	$ 249,500
Abandonment obligations	41,967	1,643	1,642	1,642	1,642	1,642	33,756
Operating lease obligations	18,328	2,373	2,390	2,436	2,446	2,493	6,190
Drilling and rig obligations	47,049	12,789	8,030	8,030	18,200	-	-
Firm natural gas transportation contracts	165,071	19,803	19,803	19,803	19,652	17,557	68,453
Total	$ 1,743,798	$ 118,819	$ 88,423	$ 88,469	$ 98,498	$ 991,690	$ 357,899

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, 2008, 2007 and 2006 was $1.7 million, $1.5 million and $1 million, respectively. In 2006, we purchased an airplane for business travel which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

Drilling obligations - In the primary term (November 2004 to November 2009) of our Utah Lake Canyon project, we have a 21 gross well drilling commitment. To date, we have drilled 14 gross wells (9.8 net wells) under theTribal Lake Canyon Exploration and Development Agreement (EDA). We have 7 remaining commitment wells to drill in Lake Canyon by the end of November 2009. Our minimum obligation under our exploration and development agreement is $9.6 million, and as of December 31, 2008 the remaining obligation is $2.4 million. Also included above, under our June 2006 joint venture agreement in Piceance, we are required to have 120 wells drilled by February 2011 to avoid penalties of $0.2 million per well or a maximum of $24 million. As of December 31, 2008 we have drilled 29 of these wells.

Drilling rig obligations - We are obligated in operating lease agreements for the use of two drilling rigs, one of which resulted from the July 2008 E. Texas Acquisition (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations).

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

Other obligations - On February 27, 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D on July 1, 2007. After partial completion of its refinery expansion in Salt Lake City in March 2008, the refiner increased its total purchase capacity to 5,000 Bbl/D. This contract is in effect through June 30, 2013. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI, which ranges from $10 to $15 at WTI prices between $40 and $60. This contract is our only sales contract for our Uinta oil.

15. Equity Compensation Plans

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

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

We adopted SFAS No. 123(R) to account for our stock option plan beginning January 1, 2006. This standard requires us to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation* effective January 1, 2004. The modified prospective method was selected as described in SFAS No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. Under this method, we recognized stock option compensation expense as if we had applied the fair value method to account for unvested stock options from the original effective date. Total compensation cost recognized in the Statements of Income was $8.9 million, $8.4 million and $6.1 million in 2008, 2007 and 2006, respectively. The tax benefit related to this compensation cost was $3.8 million, $3.3 million and $2.4 million in 2008, 2007 and 2006, 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 recipients that have similar historical exercise behavior are considered separately for valuation purposes. The expected term of options granted is based on historical exercise behavior and represents the period of time that options granted are expected to be outstanding; the range given below results from certain groups of recipients exhibiting different exercise behavior. The risk free rate for periods within the contractual life of the option is based on U.S. Treasury rates in effect at the time of grant. During 2008, the non-employee Directors did not receive any options.

	2008	2007	2006
Expected volatility	36%	32% - 33%	32% - 33%
Weighted-average volatility	36%	33%	32%
Expected dividends	1%	1%	.8% - 1.0%
Expected term (in years)	5	4.9 - 5.6	5.3 - 5.5
Risk-free rate	3.2%	3.4% - 4.7%	4.5% - 4.8%

The following table summarizes information related to stock options outstanding and exercisable as of December 31, 2008:

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
$7.00 - $15.00	682,650	$10.42	4.4	682,650	$10.42	4.4
$15.01 - $25.00	490,500	21.60	5.9	478,000	21.60	5.9
$25.01 - $35.00	933,551	31.85	7.5	590,900	31.54	7.5
$35.01 - $45.00	316,199	42.75	9.1	90,982	42.99	8.8
Total	2,422,900	$25.16	6.5	1,842,532	$21.70	6.0

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

	2008	2007	2006
Outstanding at January 1	$ 24.33	$ 20.97	$ 16.76
Granted during the year	41.18	43.40	32.82
Exercised during the year	19.38	12.52	10.83
Cancelled/expired during the year	29.66	22.88	19.11
Outstanding at December 31	25.16	24.33	20.97
Exercisable at December 31	21.70	19.88	16.24

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

	2008	2007	2006
Balance outstanding, January 1	2,527,266	2,859,836	3,110,826
Granted	89,084	220,115	604,050
Exercised	(149,950)	(444,216)	(526,990)
Canceled/expired	(43,500)	(108,469)	(328,050)
Balance outstanding, December 31	2,422,900	2,527,266	2,859,836
Balance exercisable at December 31	1,842,532	1,558,780	1,493,067
Available for future grant	412,025	988,798	1,279,344
Weighted average remaining contractual life (years)	6.5	7.3	8
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$ 14.03	$ 13.88	$ 11.27

As of December 31, 2008, there was $5.2 million of total unrecognized compensation cost related to stock options granted under the Plan. This cost is expected to be recognized over a weighted-average period of 1.4 years. The tax benefit realized from stock options exercised during the year ended December 31, 2008, 2007 and 2006 is $1.4 million, $3.5 million and $4.3 million, respectively.

	Stock Options		
	Year ended		
	December 31, 2008	December 31, 2007	December 31, 2006
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$ 14.03	$ 13.88	$ 11.27
Total intrinsic value of options exercised (in millions)	4.4	11.9	11.8
Total intrinsic value of options outstanding (in millions)	-	50.8	29.8
Total intrinsic value of options exercisable (in millions)	-	38.3	22.3

Restricted Stock Units

Under the 2005 Equity Plan, we began a long-term incentive program whereby restricted stock units (RSUs) are available for grant to certain employees and non-employee Directors. Granted RSUs generally vest at either 25% per year over 4 years or 100% after 3 years. Unearned compensation under the restricted stock award plan is amortized over the vesting period. During 2008, the non-employee Directors did not receive any RSUs. The RSUs granted to the non-employee Directors are 100% vested at date of grant but are subject to a deferral election before the corresponding shares are issued of a minimum of four years or until they leave the Board of Directors or upon change of control. We pay cash compensation on the RSUs in an equivalent amount of actual dividends paid on a per share basis of our outstanding common stock.

The following is a summary of RSU activity for the year ended December 31, 2008:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	506,923	$ 34.84	2.7 years
Granted	572,102	11.26	
Converted	(73,414)	33.95	
Canceled/expired	(39,413)	37.58	
Balance outstanding, December 31	966,198	$ 20.83	3.0 years

	RSUs Year ended		
	December 31, 2008	December 31, 2007	December 31, 2006
Weighted-average grant date fair value of RSUs issued	$11.26	$ 42.36	$ 31.86
Total value of RSUs vested (in millions)	.8	2.1	1.0

The total compensation cost related to nonvested awards not yet recognized on December 31, 2008 is $13.3 million and the weighted average period over which this cost is expected to be recognized is 1.5 years.

16. 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. Our contributions to the 401(k) Plan, net of forfeitures, were $1.4 million, $1.4 million and $1.2 million for 2008, 2007 and 2006, 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 2008.

17. 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 compensation for service and to defer recognition of their compensation in whole or in part to a Stock Unit Account or an Interest Account. When the eligible director ceases to be a director, the distribution from the Stock Unit Account shall be made in shares using an established market value date. The distribution from the Interest Account shall be made in cash. The aggregate number of shares which may be issued to eligible directors under the plan shall not exceed 500,000, subject to adjustment for corporate transactions that change the amount of outstanding stock. The plan may be amended at any time, but not more than once every six months, by the Compensation Committee or the Board of Directors. Shares earned and deferred in accordance with the plan as of December 31, 2008, 2007 and 2006 were 23,312, 12,866 and 13,387, respectively.

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

18. Hedging

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

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to our hedging activities, we utilize multiple counterparties on our hedges and monitor each counterparty's credit rating. We are not required to issue collateral on these hedging transactions. Additionally, our valuation of derivatives reflects an adjustment for the credit risk for each party based on credit default swaps when such data is available and historical default rates when such data is not available. As of December 31, 2008 and 2007, we recorded a credit risk reduction of $632 thousand and $0, respectively, to the Fair value of derivatives asset.

We entered into derivative contracts (natural gas swaps and collar contracts) in March 2006 that did not qualify for hedge accounting under SFAS 133 because the price index for the location in the derivative instrument did not correlate closely with the item being hedged. These contracts were recorded in 2006 at their fair value on the Balance Sheet and we recognized an unrealized net loss of approximately $4.8 million on the Statements of Income under the caption "Commodity derivatives." We entered into natural gas basis swaps on the same volumes and maturity dates as the previous hedges in May 2006 which allowed for these derivatives to be designated as cash flow hedges going forward. We recognized an unrealized net gain of $5.6 million in 2006. The net gain of $0.8 million was recorded in other accumulated comprehensive income (loss) at the date the hedges were designated and will be amortized to revenue as the related sales occur.

Additionally, in June 2006 and July 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility for five years. These interest rate swaps have been designated as cash flow hedges. In 2008, $50 million of these interest rate swaps were extended one year, resulting in a fixed rate of approximately 4.8%.

In 2008 we also entered into three year interest rate swaps for a fixed rate of approximately 2.2% on an additional $275 million of our outstanding borrowings under our credit facility for three years beginning on April and September 15, 2009. These interest rate swaps have been designated as cash flow hedges.

The related cash flow impact of our derivative activities are reflected as cash flows from operating activities. At December 31, 2008, our net fair value of derivatives asset was $185.9 million as compared to a derivatives liability of $201.6 million at December 31, 2007. Based on NYMEX strip pricing as of December 31, 2008, we expect to receive hedge payments under the existing derivatives of $120.5 million during the next twelve months. At December 31, 2008 and 2007, Accumulated Other Comprehensive Income (Loss) consisted of an unrealized gain of $113.7 million and an unrealized loss of $120.7 million, respectively, net of tax, from our crude oil, natural gas and interest swaps and collars that qualified for hedge accounting treatment at December 31, 2008. Deferred net gains recorded in Accumulated Other Comprehensive Income (Loss) at December 31, 2008 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts.

Most of our oil hedges are based on the West Texas Intermediate (WTI) index and our California oil sales contract with BWOC is tied to WTI which has allowed us to qualify for hedge accounting and effectively hedge our production. Our interim sales contracts are primarily based on the field posting price and we are therefore subject to potential ineffectiveness. There is a high correlation between WTI and the field posting prices which allowed us to continue hedge accounting. Additionally, under the dollar offset method, we did not have any ineffectiveness under these contracts.

19. Master Limited Partnership

On October 22, 2007, we announced plans to form a master limited partnership (MLP). We decided not to proceed with this plan due to unfavorable capital market conditions and expensed $0.6 million of legal and accounting fees during 2008 under the caption "general and administrative" in the Statements of Income related to the formation of the MLP.

20. Related Party Transaction

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

21. Subsequent Events

On February 19, 2009, the company executed an amendment to its senior secured credit facility which, among other things, increased the maximum EBITDAX to total funded debt ratio to 4.75 through year-end 2009, to 4.50 through year-end 2010 and to 4.0 thereafter. A new senior secured debt to EBITDAX covenant limits the maximum EBITDAX to outstanding debt under our senior secured credit facility to 3.75 through September 2010, 3.5 from October 2010 through March 2011, 3.25 from April 2011 through September 2011 and 3.0 thereafter. Additionally, the write off of $38.5 million to bad debt expense associated with the bankruptcy of Big West will be excluded from the calculation of EBITDAX. The LIBOR and prime rate margins increased to between 2.25% and 3.0% based on the ratio of credit outstanding to the borrowing base. Additionally, the annual commitment fee on the unused portion of the credit facility increased to 0.50%, regardless of the amount outstanding. The deferred costs of this amendment of $4.5 million will be amortized over the remaining term of the facility.

22. Quarterly Financial Data (Unaudited)

The following is a tabulation of unaudited quarterly operating results for 2008 and 2007 (in thousands, except per share data).

2008	Operating Revenues	Income (Loss) Before Taxes	Net Income(Loss)	Basic Net Income(Loss) Per Share	Diluted Net Income(Loss) Per Share
First Quarter	$ 183,653	$ 70,696	$ 43,031	$ .97	$ .96
Second Quarter	213,842	77,795	49,141	1.10	1.08
Third Quarter	239,463	83,968	53,348	1.20	1.17
Fourth Quarter (1)	160,294	(21,837)	(11,991)	(0.27)	(0.27)
	$ 797,252	$ 210,622	$ 133,529	$ 3.00	$ 2.94

2007	Operating Revenues	Income (Loss) Before Taxes	Net Income(Loss)	Basic Net Income(Loss) Per Share	Diluted Net Income(Loss) Per Share
First Quarter	$ 116,369	$ 31,149	$ 18,855	$ 0.43	$ 0.42
Second Quarter	127,293	85,778	51,957	1.18	1.16
Third Quarter	130,974	42,273	26,855	0.61	0.60
Fourth Quarter	148,383	51,431	32,261	0.73	0.71
	$ 523,019	$ 210,631	$ 129,928	$ 2.95	$ 2.89

(1) Includes $38.5 million of bad debt expense related to the allowance for bad debt taken for the bankruptcy of BWOC.

23. 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):

	2008	2007	2006
Property acquisitions			
Proved properties	$ 667,996	$ -	$ 33,390
Unproved properties	-	56,247	224,450
Development (1)	385,599	278,398	277,613
Exploration (2)	32,909	23,325	22,435
	$ 1,086,504	$ 357,970	$ 557,888

(1) *Development costs include $0.1 million, $1.2 million and $0.5 million charged to expense during 2008, 2007 and 2006, respectively.*

(2) *Exploration costs include $2.4 million, $5.2 million and $3.8 million that were charged to expense during 2008, 2007 and 2006, respectively. Exploration costs include $23.2 million and $18.1 million of capitalized interest in 2008 and 2007, respectively.*

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

	2008	2007	2006
Sales to unaffiliated parties	$ 697,977	$ 467,400	$ 430,497
Production costs	(229,996)	(158,433)	(132,298)
Depreciation, depletion and amortization	(138,237)	(93,691)	(67,668)
Dry hole, abandonment, impairment and exploration	(12,316)	(13,657)	(12,009)
	317,428	201,619	218,522
Income tax expense	(116,179)	(77,250)	(85,970)
Results of operations from producing and exploration activities	$ 201,249	$ 124,369	$ 132,552

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

The following disclosures of oil and gas reserves are based on estimates prepared by independent engineering consultants as of December 31, 2008, 2007 and 2006. Such estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. These estimates do not include probable or possible reserves. The information provided does not represent management's estimate of our expected future cash flows or value of proved oil and gas reserves.

Changes in estimated reserve quantities

The net interest in estimated quantities of proved developed and undeveloped reserves of crude oil and natural gas at December 31, 2008, 2007 and 2006, and changes in such quantities during each of the years then ended were as follows (in thousands):

	2008			2007			2006		
	Oil Mbbl	Gas MMcf	MBOE	Oil Mbbl	Gas MMcf	MBOE	Oil Mbbl	Gas MMcf	MBOE
Proved developed and Undeveloped reserves:									
Beginning of year	116,602	315,464	169,179	112,538	226,363	150,262	103,733	135,311	126,285
Revision of previous estimates	(10,211)	(41,570)	(17,139)	(3,826)	3,358	(3,262)	(512)	(222)	(553)
Improved recovery	7,600	-	7,600	4,500	-	4,500	11,900	-	11,900
Extensions and discoveries	18,700	145,800	43,000	17,300	101,400	34,200	4,100	78,000	17,100
Property sales	-	-	-	(6,700)	-	(6,700)	-	-	-
Production	(7,440)	(25,559)	(11,700)	(7,210)	(15,657)	(9,819)	(7,183)	(12,526)	(9,270)
Purchase of reserves in place	-	330,000	55,000	-	-	-	500	25,800	4,800
End of year	125251	724,135	245,940	116,602	315,464	169,179	112,538	226,363	150,262
Proved developed reserves:									
Beginning of year	78,339	147,346	102,897	84,782	104,934	102,270	78,308	70,519	90,061
End of year	74,616	361,575	134,879	78,339	147,346	102,897	84,782	104,934	102,270

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

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

	2008	2007	2006
Future cash inflows	$ 7,384,692	$ 11,211,151	$ 6,195,547
Future production costs	(2,920,664)	(3,275,397)	(2,497,785)
Future development costs	(1,196,394)	(812,070)	(511,886)
Future income tax expense	(511,291)	(2,286,296)	(892,669)
Future net cash flows	2,756,343	4,837,388	2,293,207
10% annual discount for estimated timing of cash flows	(1,620,762)	(2,417,882)	(1,110,939)
Standardized measure of discounted future net cash flows	$ 1,135,581	$ 2,419,506	$ 1,182,268
Average sales prices at December 31:			
Oil ($/Bbl)	$ 30.03	$ 79.19	$ 46.15
Gas ($/Mcf)	$ 4.85	$ 6.27	$ 4.45
BOE Price	$ 30.92	$ 66.27	$ 41.23

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

	2008	2007	2006
Standardized measure - beginning of year	$ 2,419,506	$ 1,182,268	$ 1,251,380
Sales of oil and gas produced, net of production costs	(497,866)	(326,174)	(300,619)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	(2,686,941)	1,451,140	(350,877)
Revisions of previous quantity estimates	(144,466)	(78,758)	(7,359)
Improved recovery	64,058	108,655	158,213
Extensions and discoveries	362,435	825,775	227,348
Change in estimated future development costs	(493,778)	(385,656)	(333,663)
Purchases of reserves in place	667,862	-	33,390
Sales of reserves in place	-	(98,680)	-
Development costs incurred during the period	397,601	281,702	277,075
Accretion of discount	354,672	162,257	125,138
Income taxes	631,372	(687,103)	109,918
Other	61,126	(15,920)	(7,676)
Net increase (decrease)	(1,283,925)	1,237,238	(69,112)
Standardized measure - end of year	$ 1,135,581	$ 2,419,506	$ 1,182,268

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, 2008, 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, 2008, 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 we file or submit 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, 2008.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2008 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers and Corporate Governance

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

Item 11. Executive Compensation

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

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

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

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

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

Item 14. Principal Accounting Fees and Services

The information called for by Item 14 is incorporated by reference from the information under the caption "Fees to Independent Registered Public Accounting Firms for 2008 and 2007" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Financial Statements and Schedules

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

B. Exhibits

Exhibit No.	Description of Exhibit
3.1*	Registrant's Amended and Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2006, File No. 1-09735).
3.2*	Registrant's Restated Bylaws dated July 1, 2005 (filed as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005, File No. 1-09735).
4.1*	First Supplemental Indenture, dated as of October 24, 2006, between the Registrant and Wells Fargo Bank, National Association as Trustee relating to the Registrant's 8 1/4% Senior Subordinated Notes due 2016 (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K on October 25, 2006 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*	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).
10.2*	Description of Short-Term Cash Incentive Plan of Registrant (filed as Exhibit 10.1 to the Registrant's Annual Report on Form 10-K for the period ended December 31, 2006, File No. 1-0735).
10.3*	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).
10.4*	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).
10.5*	First Amendment to the Registrant's Amended and Restated 1994 Stock Option Plan dated as of June 23, 2006 (filed as Exhibit 99.3 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.6*	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).
10.7*	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).
10.8*	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).
10.9*	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).
10.10*	Form of Restricted Stock Award Agreement, by and between Registrant and selected directors (filed as Exhibit 99.1 on Form 8-K filed on December 17, 2007, File No. 1-9735).
10.11*	Form of Restricted Stock Award Agreement, by and between Registrant and selected officers (filed as Exhibit 99.1on Form 8-K December 17, 2007, File No. 1-9735).
10.12*	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).
10.13*	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).
10.14*	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).
10.15*	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and David D. Wolf (Filed as Exhibit 10.1 in Registrant's Form 8-K/A filed on November 21, 2008, File No. 1-9735)
10.16*	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and Michael Duginski (filed as Exhibit 10.1 in Registrant's Form 8-K/A filed on November 21, 2008, File No. 1-9735)

10.17* 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).

10.18* 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).

10.19* 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).

10.20* Amended and Restated Credit Agreement, dated as of July 15, 2008 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 period ended June 30, 2008, File No. 1-9735).

10.21* Credit Agreement by and among Berry Petroleum Company, Societe Generale, SG Americas Securities, LLC, BNP Paribas Securities Corp., BNP Paribas, and other financial institutions date July 31, 2008 (filed as Exhibit 10.2 on Form 10-Q for the period ended September 30, 2008, File No. 1-9735).

10.22* First Amendment to Amended and Restated Credit Agreement, by and between Berry Petroleum Company, Wells Fargo Bank, N.A. and other financial institutions, dated as of October 17, 2008 (filed on October 17, 2008, as Exhibit 10.1 to the Registrant's Current Report on Form 8-K File No. 1-9735).

10.23* Joinder Agreement dated November 13, 2008 by and among Berry Petroleum Company, Wells Fargo Bank, N.A., and Bank of Montreal (filed as Exhibit 10.1in Registrant's Form 8-K filed on November 17, 2008, File No. 1-9735).

10.24* Joinder Agreement dated December 2, 2008 by and among Berry Petroleum Company, Wells Fargo Bank, N.A., and Calyon New York Branch (filed as Exhibit 10.1in Registrant's Form 8-K filed on December 4, 2008, File No. 1-9735).

10.25* 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).

10.26* 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).

10.27* ** 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).

10.28* 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).

10.29* ** Crude Oil Supply Agreement between the Registrant and Holly Refining and Marketing Company - Woods Cross (filed as Exhibit 10.22 to the Registrant's Annual Report on Form 10-K for the period ended December 31,2006, File No. 1-0735).

10.30* ** Purchase and Sale Agreement between the Registrant and Venoco, Inc. dated March 19, 2007 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2007, File No. 1-9735).

10.31* Purchase and Sale Agreement Between O'Brien Resources, LLC, Sepco II, LLC, Liberty Energy, LLC, Crow Horizons Company and O'Benco II LP collectively as Seller and Berry Petroleum Company as Purchaser, dated as of June 10, 2008 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 1-9735).

10.32* Overriding Royalty Purchase Agreement Between O'Brien Resources, LLC, as Seller and Berry Petroleum Company as Purchaser, dated as of June 10, 2008 (filed as Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 1-9735).

10.33* Second Amendment to the Amended and Restated Credit Agreement, dated as of February 19, 2009 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K on February 20, 2009, File NO. 1-9735).

12.1 Ratio of Earnings to Fixed Charges

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 25, 2009.

BERRY PETROLEUM COMPANY

/s/ Robert F. Heinemann	/s/ David D. Wolf	/s/ Shawn M. Canaday
ROBERT F. HEINEMANN	DAVID D. WOLF	SHAWN M. CANADAY
President, Chief Executive Officer and Director	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	Vice President and 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 25, 2009
/s/ Robert F. Heinemann Robert F. Heinemann	President, Chief Executive Officer and Director	February 25, 2009
/s/ Joseph H. Bryant Joseph H. Bryant	Director	February 25, 2009
/s/ Ralph B. Busch, III Ralph B. Busch, III	Director	February 25, 2009
/s/ William E. Bush, Jr. William E. Bush, Jr.	Director	February 25, 2009
/s/ Stephen L. Cropper Stephen L. Cropper	Director	February 25, 2009
/s/ J. Herbert Gaul, Jr. J. Herbert Gaul, Jr.	Director	February 25, 2009
/s/ Thomas J. Jamieson Thomas J. Jamieson	Director	February 25, 2009
/s/ J. Frank Keller J. Frank Keller	Director	February 25, 2009
/s/ Ronald J. Robinson Ronald J. Robinson	Director	February 25, 2009

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Directors

Robert F. Heinemann
President and Chief Executive Officer, Berry Petroleum Company

Martin H. Young, Jr. (1)
Chairman of the Board
Senior Vice President and Chief Financial Officer, Falcon Seaboard Diversified, Inc.

Joseph H. Bryant (2)
Chairman and Chief Executive Officer, Cobalt International Energy, L.P.

Ralph B. Busch, III (2,3)
Executive Vice President and Chief Operating Officer, Aon Risk Services of Central California

William E. Bush, Jr. (3C)
Marketing Consultant and Private Investor

Stephen L. Cropper (1)
Consultant and Private Investor

J. Herbert Gaul, Jr. (1C)
Private Investor

Thomas J. Jamieson (1,2C)
President and Chief Executive Officer, Jaco Oil Company

J. Frank Keller (3)
Private Investor

Ronald J. Robinson (3)
Chairman and Chief Executive Officer, Knowledge Deployment, Inc. and Private Investor

Committees:
Audit (1), Compensation (2), Corporate Governance & Nominating (3), Chairman (C)

Executive Officers

Robert F. Heinemann
President and Chief Executive Officer

Michael Duginski
Executive Vice President and Chief Operating Officer

David D. Wolf
Executive Vice President and Chief Financial Officer

Dan G. Anderson
Vice President of Rocky Mountain and Mid-Continent Production

Walter B. Ayers
Vice President of Human Resources

G. Timothy Crawford
Vice President of California Production

Bruce S. Kelso
Vice President of Rocky Mountain and Mid-Continent Exploration

Shawn M. Canaday
Vice President and Controller

Kenneth A. Olson
Corporate Secretary

Steven B. Wilson
Treasurer

General Shareholder Information

Shareholders and members of the investment community should direct inquiries to:

INVESTOR RELATIONS

Todd A. Crabtree
Berry Petroleum Company
5201 Truxtun Ave., Bakersfield, CA 93309
661-616-3900
Toll Free: 866-IR AT BRY (866-472-8279)
E-mail: ir@bry.com

TRANSFER AGENT/REGISTRAR

BNY Mellon Shareholder Services
Mailing address for Shareholder inquiries:
480 Washington Blvd., Jersey City, NJ 07310-1900
US Shareholders: 866-258-7139
TDD for Hearing Impaired: 800-231-5469
Foreign Shareholders: 201-680-6578
TDD for Foreign Shareholders: 201-680-6610
www.bnymellon.com/shareowner/isd

SECURITIES

Class A Common Stock of Berry Petroleum Company is traded on the NYSE under the symbol BRY.

FORM 10-K

Berry Petroleum Company's Form 10-K, a corporate operational and financial report filed annually with the Securities and Exchange Commission, is included in this publication, except for exhibits that are available without charge to Shareholders upon written request to Investor Relations.

DIVIDEND PAYMENT DATES

Quarterly dividends on common stock are paid, following declaration by the Board of Directors, on approximately the 29th day of March, June, September and December. The total dividend paid in 2008 was $.30 per share.

COUNSEL

Musick, Peeler & Garrett, LLP
2801 Townsgate Rd., Ste. 200, Westlake Village, CA 91361

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PricewaterhouseCoopers LLP
350 South Grand Ave., Los Angeles, CA 90071

www.bry.com

Berry's Web site offers Shareholders and potential investors quick and easy access to information about the Company's history, operations and results. The expanded Investor Center provides timely links to Berry's corporate governance, stock performance, SEC filings, recent news, and upcoming events. Visitors have the option to sign up for e-mail alerts to receive e-mail notifications each time the Web site is updated with new information.

Safe harbor under the Private Securities Litigation Reform Act of 1995

Statements in this annual report that are not historical facts are forward-looking statements that involve risks and uncertainties. Words that imply future events or results are forward-looking statements based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. Many factors could affect actual results and these items are discussed at length in Part I, Item 1A on page 15 of our Form 10-K filed with the Securities and Exchange Commission and included in this document.

BERRY PETROLEUM COMPANY

1999 Broadway, Suite 3700, Denver, CO 80202
Phone: 303-999-4400

INVESTOR RELATIONS

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LISTED
NYSE