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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (date of earliest event reported): **August 11, 2009**

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

Delaware	**1-9735**	**77-0079387**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

1999 Broadway, Suite 3700, Denver, Colorado	**80202**
(Address of Principal Executive Offices)	(Zip Code)

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

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

ITEM 8.01 OTHER EVENTS.

Berry Petroleum Company (the "Company") is filing this Current Report on Form 8-K to update the following items of the Company's Annual Report on Form 10-K for the year ended December 31, 2008 (the "Form 10-K") as set forth under the corresponding items contained in Exhibit 99.1, which is incorporated herein by reference:

- Item 6. Selected Financial Data;
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation; and
- Item 8. Financial Statements and Supplementary Data.

These updates are being made to reflect (1) the presentation as discontinued operations of the Company's natural gas assets in the Denver-Julesburg basin in Colorado (the "DJ Basin assets") in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, and (2) the Company's implementation of FASB Staff Position No. EITF 03-06-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP EITF 03-06-01"), which requires the revision of prior period basic and diluted earnings per share data.

As previously disclosed, the Company sold its DJ Basin assets on April 1, 2009. SFAS 144 requires the Company to report in discontinued operations the results of operations of a property that has either been disposed of or is classified as held for sale, unless certain conditions are met. SFAS 144 further requires the Company to reclassify results of operations from a property disposed or designated as held for sale as income from discontinued operations during all reported periods. This Current Report on Form 8-K sets forth, among other things, audited financial statements of the Company for the years ended December 31, 2006, 2007 and 2008, including revised notes thereto, which reflect the impact of reclassifying results of operations from the DJ Basin assets in accordance with SFAS 144.

Also as previously disclosed, on January 1, 2009, the Company adopted FSP EITF 03-06-1. FSP EITF 03-06-1 clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. As a result, all prior period earnings per share data presented in the Form 10-K have been updated to conform with the provisions of this pronouncement.

This Current Report on Form 8-K does not reflect events or developments that occurred after February 25, 2009, the date the Company filed the Form 10-K with the Securities and Exchange Commission (the “SEC”). More current information is contained in the Company’s Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009 and June 30, 2009 (the “Form 10-Qs”) and other filings with the SEC. The information in this Current Report on Form

8-K should be read in conjunction with the Form 10-K, the Form 10-Qs and other documents the Company filed with the SEC subsequent to February 25, 2009.

ITEM 9.01 FINANCIAL STATEMENTS AND EXHIBITS.

(d) Exhibits.

EXHIBIT NUMBER		DESCRIPTION
23.1	—	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
99.1	—	Item 6. Selected Financial Data, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operation and Item 8. Financial Statements and Supplementary Data (updating Part II, Items 6, 7 and 8 of the Form 10-K filed on February 25, 2009).

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

BERRY PETROLEUM COMPANY

By: /s/ Shawn M. Canaday
Shawn M. Canaday
Assistant Secretary

Date: August 11, 2009

INDEX TO EXHIBITS

EXHIBIT NUMBER		DESCRIPTION
23.1	—	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
99.1	—	Item 6. Selected Financial Data, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operation and Item 8. Financial Statements and Supplementary Data (updating Part II, Items 6, 7 and 8 of the Form 10-K filed on February 25, 2009).

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 333-127018, 333-98379, 333-62871 and 333-62799) of Berry Petroleum Company of our report dated February 25, 2009, except with respect to our opinion on the financial statements insofar as it relates to the discontinued operations discussed in Note 1 and the change in accounting for earnings per share discussed in Note 23, as to which the date is August 11, 2009, relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 8-K.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
August 11, 2009

99.1 Item 6. Selected Financial Data, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation and Item 8. Financial Statements and Supplementary Data (updating Part II, Items 6, 7 and 8 of the Form 10-K filed on February 25, 2009).

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 and have been revised from the presentation, except for the reserve data, in our Annual Report on Form 10-K to reflect (1) the presentation as discontinued operations of our DJ Basin assets, which were sold on April 1, 2009, in accordance with the Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-lived Assets*, and (2) our implementation of FASB Staff Position No. EITF 03-06-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, which requires the revision of prior period basic and diluted earnings per share data. The Statements of Income for the years ended December 31, 2008, 2007 and 2006 and Balance Sheet data as of December 31, 2008 and 2007 included in this table 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
Financial Information					
Sales of oil and gas	$ 649,248	$ 433,208	$ 396,497	$ 324,473	$ 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	103	130	410
Operating costs - oil and gas production	188,758	130,940	111,490	93,423	73,838
Operating costs - electricity generation	54,891	45,980	48,281	55,086	46,191
Gas marketing expense	32,072	—	—	—	—
Production taxes	26,876	14,651	12,169	10,462	6,431
General and administrative expenses (G&A)	54,279	39,663	36,474	21,270	22,504
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	125,595	82,861	61,419	34,320	29,752
Electricity generation	2,812	3,568	3,343	3,260	3,490
Income from continuing operations	121,776	127,284	97,857	103,684	69,187
Income from discontinued operations, net of taxes	11,753	2,644	10,086	8,672	—
Net income	133,529	129,928	107,943	112,356	69,187
Basic net income from continuing operations per share	$ 2.70	$ 2.85	$ 2.21	$ 2.34	$ 1.58
Basic net income from discontinued operations per share	$ 0.26	$ 0.06	$ 0.23	$ 0.20	$ —
Basic net income per share	$ 2.96	$ 2.91	$ 2.44	$ 2.54	$ 1.58
Diluted net income from continuing operations per share	$ 2.66	$ 2.81	$ 2.18	$ 2.31	$ 1.54
Diluted net income from discontinued operations per share	$ 0.26	$ 0.06	$ 0.22	$ 0.19	$ —
Diluted net income per share	$ 2.92	$ 2.87	$ 2.40	$ 2.50	$ 1.54
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	0.30	0.30	0.30	0.30	0.26
Cash flow from operations	409,569	238,879	258,475	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 continuing operations (per BOE (4)):					
Average sales price before hedging	$ 73.64	$ 52.30	$ 50.01	$ 46.11	$ 33.64
Average sales price after hedging	62.03	49.80	48.09	40.60	30.32
Average operating costs - oil and gas production	17.99	15.09	13.45	12.06	10.09
Production taxes	2.56	1.69	1.47	1.35	.86
G&A	5.17	4.57	4.40	2.75	2.99
DD&A - oil and gas production	$ 11.97	$ 9.55	$ 7.41	$ 4.43	$ 3.96
Total Production (MBOE)	11,700	9,819	9,270	8,401	7,517
DJ Basin Production (MBOE)	1,206	1,140	978	656	—
Production – Continuing operations (MBOE)(4)	10,494	8,679	8,292	7,745	7,517
Production (MMWh)	755	779	757	741	776
Total proved reserves (BOE) (3)	245,940	169,179	150,262	126,285	109,836
Standardized measure (2) (3)	$ 1,135,581	$ 2,419,506	$ 1,182,268	$ 1,251,380	$ 686,748
Year end average BOE price for PV10 purposes (3)	$ 30.03	$ 66.27	$ 41.23	$ 48.21	$ 29.87
Return on average shareholders' equity (3)	20.74%	29.18%	28.33%	37.63%	31.06%
Return on average capital employed (3)	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).
(3) Does not give effect to the DJ basin asset sale.
(4) Gives effect to the DJ basin asset sale and represents continuing operations only

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

As previously disclosed, the Company sold its DJ Basin assets on April 1, 2009. SFAS 144 requires the Company to report in discontinued operations the results of operations of a property that has either been disposed of or is classified as held for sale, unless certain conditions are met. SFAS 144 further requires the Company to reclassify results of operations from a property disposed or designated as held for sale as income from discontinued operations during all reported periods. This Current Report on Form 8-K sets forth, among other things, audited financial statements of the Company for the years ended December 31, 2008, 2007 and 2006, including revised notes thereto, which reflect the impact of reclassifying results of operations from the DJ Basin assets in accordance with SFAS 144.

Also as previously disclosed, on January 1, 2009, the Company adopted FSP EITF 03-06-1. FSP EITF 03-06-1 clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. As a result, all prior period earnings per share data presented in the Form 10-K have been updated to conform with the provisions of this pronouncement.

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 from continuing operations of 32,168 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 from continuing operations of $11.1 million, or $0.24 per diluted share. Net cash from operations was $78 million and capital expenditures during the quarter totaled $92 million. The net loss from continuing operations 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. We had a net loss from discontinued operations of $0.9 million resulting from the DJ basin operations.

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.

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.

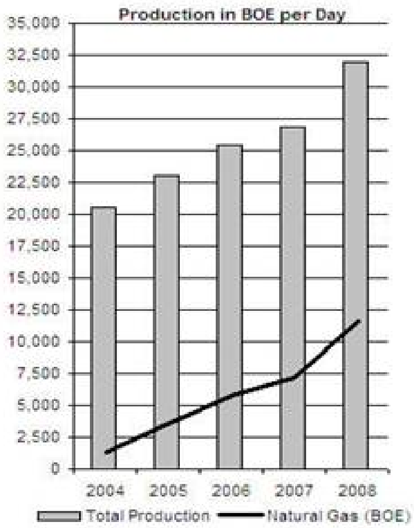
2009 — The primary focus in 2009 will be to maximize production from our existing wells, increase operational efficiencies, and reduce lease operating expense. Our capital program will be directed toward lease acquisition and facility infrastructure upgrades.

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 50% in 2008 compared to 2007 and up 64% 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 71% of the revenue increase and the increase in production volumes contributed the other 29%. 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.

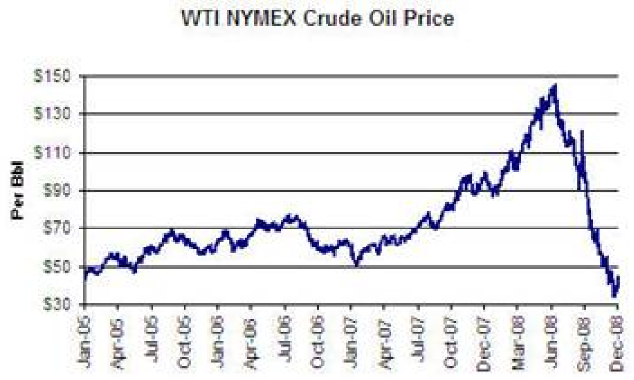
The following results are in millions (except per share data) for the years ended December 31:

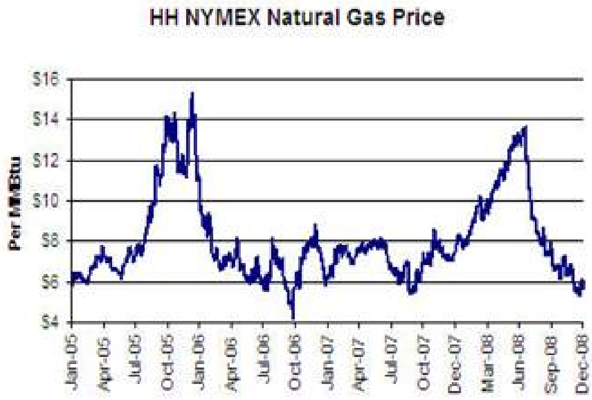
	2008	2007	2006
Sales of oil	$ 519	$ 385	$ 360
Sales of gas	130	48	36
Total sales of oil and gas	$ 649	$ 433	$ 396
Sales of electricity	64	56	53
Gas marketing	36	—	—
Gain (loss) on sale of assets (1)	(1)	54	—
Interest and other income, net	3	4	2
Total revenues and other income	$ 751	$ 547	$ 451
Net income from continuing operations	$ 122	$ 127	$ 98
Diluted earnings per share from continuing operations	$ 2.66	$ 2.81	$ 2.18

(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	38	14	49
Total sales of oil and gas	$ 135	$ 123	$ 194
Sales of electricity	12	15	18
Gas marketing	8	—	13
Gain (loss) on sale of assets	(2)	2	—
Interest and other income, net	1	2	1
Total revenues and other income	$ 154	$ 142	$ 226
Net income from continuing operations (loss)	$ (11)	$ 30	$ 50
Diluted (loss) earnings per share from continuing operations	$ (0.24)	$ 0.65	$ 1.08





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 Production (BOE/D)	31,968	100	26,902	100	25,398	100
DJ Basin production	3,295		3,123		2,679	
Production — Continuing Operations (BOE/D)	28,673		23,779		22,719	
Oil and gas, per BOE for continuing operations						
Average sales price before hedging	$ 73.64		$ 52.30		$ 50.01	
Average sales price after hedging	62.03		49.80		48.09	
Oil, per Bbl for continuing operations:						
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 for continuing operations:						
Average Henry Hub price per MMBtu	$ 9.04		$ 7.12		$ 6.97	
Conversion to Mcf	.46		.36		.33	
Natural gas hedges	.20		1.31		.16	
Location, quality differentials and other	(2.59)		(3.31)		(2.08)	
Average gas sales price after hedging	$ 7.11		$ 5.48		$ 5.38	

Production from continuing operations increased 21% or 4,894 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

DJ Basin production	3,415	3,332	3,337
Production — Continuing Operations (BOE/D)	32,168	24,691	31,813
Oil and gas, per BOE for continuing operations			
Average sales price before hedging	$ 40.61	$ 64.15	$ 83.90
Average sales price after hedging	45.56	54.99	67.04
Oil, per Bbl for continuing operations:			
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 for continuing operations:			
Average Henry Hub price per MMBtu	$ 6.95	$ 7.39	$ 10.24
Conversion to Mcf	.35	.37	.51
Natural gas hedges	.89	1.55	0.20
Location, quality differentials and other	(2.67)	3.87)	(2.69)
Average gas sales price after hedging	$ 5.52	$ 5.44	$ 8.26

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 continuing operations 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	$ 17.99	$ 15.09	19%	$ 188,758	$ 130,940	44%
Production taxes	2.56	1.69	51%	26,876	14,651	83%

DD&A - oil and gas production	11.97	9.55	25%	125,595	82,861	52%
G&A	5.17	4.57	13%	54,279	39,663	37%
Interest expense	2.28	1.74	31%	23,942	15,069	59%
Total	$ 39.97	$ 32.64	22%	$ 419,450	$ 283,184	48%

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 $58 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 25% 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 continuing operations 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	$ 15.09	$ 13.45	12%	$ 130,940	$ 111,490	17%
Production taxes	1.69	1.47	15%	14,651	12,169	20%
DD&A - oil and gas production	9.55	7.41	29%	82,861	61,419	35%
G&A	4.57	4.40	4%	39,663	36,474	9%
Interest expense	1.74	1.07	63%	15,069	8,894	69%
Total	$ 32.64	$ 27.80	17%	$ 283,184	$ 230,446	23%

Our total operating costs, production taxes, G&A and interest expenses for 2007, stated on a unit-of-production basis, increased 17% 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 29% 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	$ 17.99	$ 15.09
Production taxes (2)	1.50 – 2.00	2.56	1.69
DD&A	14.00 – 16.00	11.97	9.55
G&A	3.75 – 4.00	5.17	4.57
Interest expense	3.00 – 4.00	2.28	1.74
Total	$ 35.75 – 41.00	$ 39.97	$ 32.64

(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 $10.5 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 $0.6 million in 2008 compared to $0.6 million and $1.8 million in 2007 and 2006, respectively. These costs consist primarily of geological and geophysical costs. 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, impairment and exploration charges of $8.4 million consisting primarily of 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 36%, 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.

Discontinued Operations — In April 2009, we sold our DJ basin assets and reported net income from discontinued operations of $11.8 million in 2008 in accordance with the Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-lived Assets*.

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 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.

We generally utilize NYMEX WTI based derivates to hedge cash flows from our California oil sales. Prior to December 22, 2008, all of our crude oil in California was sold to BWOC. The Company's crude oil has a ready market in California and we entered into new contracts with multiple refiners for all of our California crude oil production and thus the probability of our hedged forecasted transactions occurring was not significantly impacted by the BWOC bankruptcy.

Our new sales contracts with multiple refiners are primarily based on the field posting prices. There is a high correlation between WTI and the field posting prices which allowed us to continue hedge accounting. Under the dollar offset method, we did not have any ineffectiveness under these hedges during 2008. However, depending on the change in value of our actual hedges compared to a hypothetical hedge based on field posting prices, ineffectiveness may be recorded in the future

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 8) and we increased production from continuing operations by 21%.

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 from continuing operations (BOE/D)	28,673	23,779	21%
Average oil and gas sales prices, per BOE after hedging	$ 62.03	$ 49.80	26%
Net cash provided by operating activities	$ 410	$ 239	72%
Working capital (deficit)	$ (72)	$ (110)	38%
Sales of oil and gas	$ 649	$ 433	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 June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP EITF 03-6-1"), which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. All prior period earnings per share data presented shall be adjusted retrospectively to conform with the provisions of this pronouncement. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. We implemented EITF 03-06-1 during the first quarter of 2009 and all periods presented herein have been revised. See Note 24 to the financial statements.

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 8. Financial Statements and Supplementary Data

	Page
Report of PricewaterhouseCoopers LLP, an Independent Registered Public Accounting Firm	22

Balance Sheets at December 31, 2008 and 2007	23
Statements of Income for the Years Ended December 31, 2008, 2007 and 2006	24
Statements of Comprehensive Income for the Years Ended December 31, 2008, 2007 and 2006	24
Statements of Shareholders' Equity for the Years Ended December 31, 2008, 2007 and 2006	25
Statements of Cash Flows for the Years Ended December 31, 2008, 2007 and 2006	26
Notes to the Financial Statements	27
Supplemental Information About Oil & Gas Producing Activities (Unaudited)	49

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 (not presented herein) appearing under Item 9A of the Company's 2008 Annual Report on Form 10-K. 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. As discussed in Note 23 to the financial statements, the Company changed the manner in which it accounts for earnings per share in 2009.

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, except with respect to our opinion on the financial statements insofar as it relates to the discontinued operations discussed in Note 1 and the change in accounting for earnings per share discussed in Note 23, as to which the date is August 11, 2009

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

	2008	2007
ASSETS		
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	$ 649,248	$ 433,208	$ 396,497
Sales of electricity	63,525	55,619	52,932
Gas marketing	35,750	—	—
Gain (loss) on sale of assets	(1,297)	54,173	103
Interest and other income, net	3,504	4,414	1,462
	750,730	547,414	450,994
EXPENSES			
Operating costs - oil and gas production	188,758	130,940	111,490
Operating costs - electricity generation	54,891	45,980	48,281
Production taxes	26,876	14,651	12,169
Depreciation, depletion & amortization - oil and gas production	125,595	82,861	61,419
Depreciation, depletion & amortization – electricity generation	2,812	3,568	3,343
Gas marketing	32,072	—	—
General and administrative	54,279	39,663	36,474
Interest	23,942	15,069	8,894
Commodity derivatives	213	(13)	(736)
Dry hole, abandonment, impairment and exploration	10,543	8,351	9,754
Bad debt expense	38,665	—	—
	558,646	341,070	291,088
Income before income taxes	192,084	206,344	159,906
Provision for income taxes	70,308	79,060	62,049
Income from continuing operations	121,776	127,284	97,857
Income from discontinued operations, net of tax	11,753	2,644	10,086

Net income	$	133,529	$	129,928	$	107,943
Basic net income from continuing operations per share		2.70		2.85		2.21
Basic net income from discontinued operations per share		0.26		0.06		0.23
Basic net income per share	$	2.96	$	2.91	$	2.44
Diluted net income from continuing operations per share		2.66		2.81		2.18
Diluted net income from discontinued operations per share		0.26		0.06		0.22
Diluted net income per share	$	2.92	$	2.87	$	2.40

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

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	—	—	—	(13,425)	—	(13,425)

dividend equivalents						
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.

As previously disclosed, the Company sold its DJ Basin assets on April 1, 2009. SFAS 144 requires the Company to report in discontinued operations the results of operations of a property that has either been disposed of or is classified as held for sale, unless certain conditions are met. SFAS 144 further requires the Company to reclassify results of operations from a property disposed or designated as held for sale as income from discontinued operations during all reported periods. This Current Report on Form 8-K sets forth, among other things, audited financial statements of the Company for the years ended December 31, 2008, 2007 and 2006, including revised notes thereto, which reflect the impact of reclassifying results of operations from the DJ Basin assets in accordance with SFAS 144.

Also as previously disclosed, on January 1, 2009, the Company adopted FSP EITF 03-06-1. FSP EITF 03-06-1 clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. As a result, all prior period earnings per share data presented in the Form 10-K have been updated to conform with the provisions of this pronouncement.

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, $11.8 million represents 20 days of our December crude oil sales and an administrative claim under the bankruptcy proceedings and $26.7 million represents November and the balance of December 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.

Asset retirement obligations (ARO) - - We have significant obligations to plug and abandon oil and natural gas wells and related equipment at the end of oil and gas production operations. The computation of our ARO is prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*. Under this standard, we record the fair value of the future abandonment as capitalized abandonment costs in Oil and Gas Properties with an offsetting abandonment liability. We 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.

Accrued liabilities - 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.

Revenue recognition - 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.

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

Cogeneration operations - Our investment in cogeneration facilities has been for the express purpose of lowering steam costs in our heavy oil operations and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam. We allocate steam costs to our oil and gas operating costs based on the conversion efficiency of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. Electricity used in oil and gas operations is allocated at cost. Electricity consumption included in oil and gas operating costs for the years ended December 31, 2008, 2007 and 2006 was $5.8 million, $5.0 million and $5.3 million, respectively.

Shipping and handling costs - Shipping and handling costs, consisting primarily of natural gas transportation costs, are included in either "Operating costs - oil and gas production" or "Operating costs - electricity generation," as applicable. Natural gas transportation costs included in Operating costs - oil and gas production were $7.9 million, $0 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.

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

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

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

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

Equity method investments - We own interests in two entities which serve to gather and transport natural gas in our Lake Canyon and Brundage Canyon fields. We own less than 50% interest in both entities and these interests are accounted for using the equity method. 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 June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP EITF 03-6-1"), which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. All prior period earnings per share data presented shall be adjusted retrospectively to conform with the provisions of this pronouncement. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. We implemented EITF 03-06-1 during the first quarter of 2009 and all periods presented herein have been revised. See Note 24 to the financial statements.

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, $11.8 million represents 20 days of our December crude oil sales and an administrative claim under the bankruptcy proceedings and $26.7 million represents November and the balance of December 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.

Customer	Accounts Receivable As of December 31, 2008	2007	Sales before hedging and royalties For the Year Ended December 31, 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):

	2008	2007

Oil and gas:				
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, impairment and exploration charges of $10.5 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 $0.6 million in 2008 compared to $0.6 million and $1.8 million in 2007 and 2006, respectively. These costs consist primarily of geological and geophysical costs. 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, impairment and exploration charges of $8.4 million that consisted primarily of 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 and other dry hole charges of $2.2 million.

In 2006, there was $8.0 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 for $1.2 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% Notes Due 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, $11.8 million represents 20 days of our December crude oil sales and an administrative claim under the bankruptcy proceedings and $26.7 million represents November and the balance of December 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. The unaudited pro forma results set forth below also gives effect to (1) the presentation as discontinued operation of it DJ Basin assets, which were sold on April 1, 2009, in accordance with SFAS No. 144, "*Accounting for the Impairment of Disposal of Long-Lived Assets,*" and (2) the Company's implementation of FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, which requires the revision of prior period basic and diluted earning per share data.

	Year Ended December 31, 2008	Year Ended December 31, 2007
Pro forma revenue	$ 797,261	$ 581,138
Pro forma income from operations	$ 197,196	$ 162,733
Pro forma net income	$ 125,917	$ 103,333
Pro forma basic earnings per share	$ 2.79	$ 2.34
Pro forma diluted earnings per share	$ 2.75	$ 2.30

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:

Purchase price (in thousands):		As of December 31, 2008
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 continuing operations provision for income taxes consists of the following (in thousands):

		2008		2007		2006
Current:						
Federal	$	2,991	$	12,676	$	11,088
State		5,285		5,191		4,122
		8,276		17,867		15,210
Deferred:						
Federal		56,919		52,235		40,075
State		5,113		8,958		6,764
		62,032		61,193		46,839
Total	$	70,308	$	79,060	$	62,049

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	3	5	5
Tax credits		—	—
Other	(2)	(2)	(1)
Effective tax rate	36%	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 eachcounterparty'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.

We generally utilize NYMEX WTI based derivates to hedge cash flows from our California oil sales. Prior to December 22, 2008, all of our crude oil in California was sold to BWOC. The Company’s crude oil has a ready market in California and we entered into new contracts with multiple refiners for all of our California crude oil production and thus the probability of our hedged forecasted transactions occurring was not significantly impacted by the BWOC bankruptcy.

Our new sales contracts with multiple refiners are primarily based on the field posting prices. There is a high correlation between WTI and the field posting prices which allowed us to continue hedge accounting. Under the dollar offset method, we did not have any ineffectiveness under these hedges during 2008. However, depending on the change in value of our actual hedges compared to a hypothetical hedge based on field posting prices, ineffectiveness may be recorded in the future

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. Quarterly Financial Data (Unaudited)

The following is a tabulation of unaudited quarterly operating results for 2008 and 2007 (in thousands, except per share data) and has been updated to reflect (1) the presentation as discontinued operations of the Company’s natural gas assets in the Denver-Julesburg basin in Colorado (the “DJ Basin assets”) in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, and (2) the Company’s implementation of FASB Staff Position No. EITF 03-06-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (“FSP EITF 03-06-01”), which requires the revision of prior period basic and diluted earnings per share data.

	Operating Revenues	Income (Loss) From Continuing Operations	Income (Loss) from Discontinued Operations	Net Income (Loss)	Basic Net Income(Loss) From Continuing Operations Per Share	Basic Net Income(Loss) From Discontinued Operations Per Share	Diluted Net Income(Loss) From Continuing Operations Per Share	Diluted Net Income(Loss) From Discontinued Operations Per Share
2008								
First Quarter	$ 170,824	$ 39,536	$ 3,495	43,031	$ 0.88	$ 0.08	0.86	$ 0.08
Second Quarter	197,532	43,712	5,429	49,141	0.97	0.12	0.95	0.12
Third Quarter	225,491	49,615	3,733	53,348	1.10	0.08	1.08	0.08
Fourth Quarter (1)	154,676	(11,087)	(904)	(11,991)	(0.24)	(0.02)	(0.24)	(0.02)
	$ 748,523	$ 121,776	$ 11,753	133,529	$ 2.70	$ 0.26	2.66	$ 0.26
2007								
First Quarter	$ 107,132	$ 16,909	$ 1,946	18,855	$ 0.38	$ 0.04	0.38	$ 0.04
Second Quarter	119,130	51,182	775	51,957	1.15	0.02	1.13	0.02
Third Quarter	124,203	29,495	(2,640)	26,855	0.66	(0.06)	0.65	(0.06)
Fourth Quarter	138,362	29,698	2,563	32,261	0.66	0.06	0.65	0.06
	$ 488,827	$ 127,284	$ 2,644	129,928	$ 2.85	$ 0.06	2.81	$ 0.06

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

22. Supplemental Information About Oil & Gas Producing Activities (Unaudited)

This footnote does not give effect to the sale of our DJ basin assets.

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	125,251	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.

Excluding the effect of production, reserves increased 88.5 million BOE between 2007 and 2008. 55 million BOE of the increase related to the purchase of our East Texas Asset which occurred July 15, 2008. An increase of 43 million BOE resulted from extension and discoveries from our drilling activities with significant contributions of 20 million BOE in the Piceance, 12 million BOE in the Diatomite and 4 million BOE in South Midway. Improved recovery increases were primarily from the diatomite where 7.2 million BOE was added due to the performance of our development. Revisions to previous estimates were a decrease of 17.1 million BOE, primarily from 11 million BOE of price related revisions in our California properties and 4.0 million BOE of revisions in East Texas due to lack of performance data from certain zones.

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	(352,061)	(286,439)	(215,471)
Purchases of reserves in place	667,862	—	33,390
Sales of reserves in place	—	(98,680)	—
Development costs incurred during the period	173,184	132,002	115,818
Accretion of discount	354,672	162,257	125,138
Income taxes	631,372	(687,103)	109,918
Other	143,826	34,563	35,389
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

23. Earnings per Share

In SFAS No. 128, “Earnings per Share (as amended)”, the two-class method is an earnings allocation formula that determines earnings per share for each class of stock according to dividends declared (or accumulated) and participation rights in undistributed earnings. In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (“FSP EITF 03-6-1”), which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in SFAS No. 128. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, we have adopted this pronouncement as of January 1, 2009.

All prior period earnings per share data presented were adjusted retrospectively to conform with the provisions of this pronouncement. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, we have adopted this pronouncement as of January 1, 2009.

	2008	2007	2006
Net income from continuing operations	$ 121,776	$ 127,284	$ 97,857
Less: Income allocable to participating securities	1,752	1,494	795
Income available for shareholders	120,024	125,790	97,062
Net income from discontinued operations	$ 11,753	$ 2,644	$ 10,086
Less: Income allocable to participating securities	173	32	85
Income from discontinued operations available for shareholders	11,580	2,612	10,001
Basic earnings per share from continuing operations	2.70	2.85	2.21
Basic earnings per share from discontinued operations	.26	.06	.23
Basic earnings per share	2.96	2.91	2.44
Dilutive earnings per share from continuing operations	2.66	2.81	2.18
Dilutive earnings per share from discontinued operations	.26	.06	.22

Basic earnings per share	2.92	2.87	2.40
Weighted average shares outstanding - basic	44,485	44,075	43,948
Add: dilutive effects of stock options	578	604	660
Weighted average shares outstanding - dilutive	45,063	44,679	44,608

Options to purchase 0.2 million, 0 million and 0.6 million shares were outstanding at December 31, 2008, 2007 and 2006, respectively, and were excluded from the calculation of diluted earnings per share because the options' exercise price was greater than the average market price of the shares.

Upon adoption, basic income per share decreased by $0.04, $0.04 and $0.02 for the years ended December 31, 2008, 2007 and 2006, respectively. Dilutive income per share decreased $0.02, $0.02 and $0.01 for the years ended December 31, 2008, 2007 and 2006, respectively.

24. Subsequent Events

Asset Disposition

On March 3, 2009, we entered into an agreement to sell our DJ basin assets and related hedges for $154 million before customary closing adjustments. The $14 million sale of our DJ basin related hedges was completed in March 2009. The closing date of the sale was April 1, 2009. All periods have been revised to reflect DJ basin operations as discontinued operations.

Income from discontinued operations, net of tax on our accompanying statements of income is comprised of the following (in thousands):

	For the Twelve Months Ended December 31,		
	2008	2007	2006
Oil and gas revenue	$ 48,729	34,192	$ 34,000
Other revenue	2,072	1,851	1,344
Total Revenue	50,801	36,043	35,344
Operating expenses	11,340	10,279	6,135
Production taxes	3,023	2,564	2,505
DD&A	12,642	10,829	6,248
General and administrative	1,074	547	368
Interest expense	2,267	2,218	1,353
Commodity derivatives	145	13	—
Dry hole, abandonment, impairment and exploration	1,772	5,306	2,254
Total Expenses	32,263	31,756	18,863
Income from discontinued operations, before income taxes	18,538	4,287	16,481
Income tax expense	(6,785)	(1,643)	(6,395)
Income from discontinued operations	$ 11,753	2,644	$ 10,086

Senior Secured Credit Facility Amendment

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.