Form
Unknown document format

colspan="3" style="vertical-align:bottom;border-bottom:1px solid #000000;padding-left:2px;padding-top:2px;padding-bottom:2px;padding-right:2px;">

December 31, 2011

December 31, 2010

December 31, 2009

December 31, 2011

December 31, 2010

September 30, 2011
Sales of oil
$
772,685

$
512,699

$
419,991

$
207,689

$
143,246

$
199,930

Sales of natural gas
98,088

106,909

80,541

19,609

25,359

25,395

Sales of oil and natural gas
$
870,773

$
619,608

$
500,532

$
227,298

$
168,605

$
225,325

Sales of electricity
34,953

34,740

36,065

10,750

7,427

9,826

Natural gas marketing

13,832

22,162

22,806

2,550

3,968

3,612

Settlement on Flying J
bankruptcy claim
—

21,992

—

—

—

—

Gain (loss) on sale of assets
—

—

826

—

—

—

Interest and other income, net
1,784

3,300

1,810

390

980

463

Total revenues and other income
$
921,342

$
701,802

$
562,039

$
240,988

$
180,980

$
239,226

Net (loss) earnings from continuing operations
$
(228,063
)

$

82,524

$
47,224

$
(414,733
)

$
(21,145
)

$
134,001

Diluted net (loss) earnings per share from continuing operations
$
(4.21
)

$
1.52

$
1.02

$
(7.62
)

$
(0.40
)

$
2.42

Sales of Oil and Natural Gas

Sales of oil and natural gas increased $251.2 million, or 41%, to $870.8 million in 2011 from $619.6 million in 2010. The increase was primarily due to a 10% increase in sales volumes and an increase in the average sales price to $66.91 per BOE in 2011 from $52.14 per BOE in 2010, which includes an increase in the non-cash amortization of AOCL related to discontinuing hedge accounting to $60.9 million, or $4.68 per BOE, for 2011, compared to $18.4 million, or $1.55 per BOE, for 2010. Sales of oil and natural gas increased $119.1 million, or 24%, to $619.6 million for 2010 from $500.5 million for 2009. The increase was primarily due to a 11% increase in sales volumes and an increase in the average realized sales price to $52.14 per BOE in 2010 from $46.72 per BOE in 2009, which includes an increase in the non-cash amortization of AOCL related to discontinuing hedge accounting to $18.4 million, or $1.55 per BOE, for 2010. There was no non-cash amortization of AOCL related to discontinuing hedge accounting in 2009.

Total production from continuing operations in 2011 increased 3,021 BOE/D, or 9%, to 35,687 BOE/D, from 32,666 BOE/D in 2010, primarily due to development activities and the contribution of our acquisitions in the Permian, and partially offset by more stringent operating regulations with respect to our Diatomite assets, imposed curtailments by our third-party processors in the Permian and planned production declines at our Piceance and E. Texas properties. In 2011, we drilled a total of 367 net wells compared to 232 net wells in 2010. Total production from continuing operations increased 3,397 BOE/D, or 12%, to 32,666 BOE/D in 2010 from 29,269 BOE/D in 2009, primarily due to our development activities and the contribution of our acquisitions in the Permian. In 2010, we drilled a total of 232 net wells compared to 132 net wells in 2009.

Sales of Electricity

Sales of electricity increased $0.2 million, or 1%, to $34.9 million in 2011 from $34.7 million in 2010, primarily due to the refund of $4.1 million received in December 2011 from one of our electricity customers associated with a retroactive payment adjustment for capacity. As a result of the Global Settlement, we received retroactive payments for firm capacity that had been originally paid at "as available" capacity rates, and the payment received in December 2011 represents the difference in rates over the disputed period. This increase was offset by a 6% decrease in the average sales price of electricity and a 6% decrease in electric power sold associated with an increase in cogeneration unit downtime in 2011. Operating costs—electricity generation decreased $5.6 million, or 18%, to $25.7 million in 2011 from $31.3 million in 2010 primarily due to a 6% decrease in fuel gas cost and a 6% decrease in electric power produced related to increased cogeneration unit downtime in 2011.

Sales of electricity decreased $1.3 million, or 4%, to $34.7 million in 2010 from $36.1 million in 2009, primarily due to a $1.7 million adjustment received in 2009 relating to a retroactive revision to payments received from PG&E. Operating cost—electricity generation remained relatively unchanged in 2010 compared to 2009.

Table of Contents

	Year Ended December 31,		
	2011	2010	2009
Electricity			
Sales of electricity (in thousands)	$34,953	$34,740	$36,065
Operating costs (in thousands)	$25,690	$31,295	$31,400
Electric power produced—MWh/D	1,968	2,088	2,098
Electric power sold—MWh/D	1,806	1,925	1,907
Average sales price/MWh	$47.00	$50.06	$60.99
Fuel gas cost/MMBtu (including transportation)	$4.20	$4.49	$3.86

We purchased approximately 25,000 MMBtu/D, 27,000 MMBtu/D and 27,000 MMBtu/D of natural gas as fuel in our cogeneration facilities for the years ended December 31, 2011, 2010 and 2009, respectively. We purchase and transport, on average, 12,000 MMBtu/D on the Kern River Pipeline under our firm transportation contract

Natural Gas Marketing

We have long-term firm transportation contracts on the Rockies Express, Wyoming Interstate Company (WIC), and Ruby pipelines, each with total average capacities of 35,000 MMBtu/D. Demand charges for our capacity are reflected in operating costs-oil and natural gas production in our Statements of Operations. Our current production is insufficient to fully utilize this capacity. To optimize our remaining capacity, we purchase third-party natural gas at the market rate in our producing areas utilizing FERC-approved asset management agreements. Sales and purchases of third-party natural gas are recorded under natural gas marketing in the revenues and expenses section of the Statement of Operations, respectively.

The pre-tax net of our natural gas marketing revenue and our natural gas marketing expense for the years ended December 31, 2011, 2010 and 2009 was $0.8 million, $2.3 million and $1.6 million, respectively.

Realized and Unrealized (Gain) Loss on Derivatives, Net

Realized and unrealized (gain) loss on derivatives, net is primarily related to derivative instruments for which we did not elect hedge accounting or derivatives which did not qualify for hedge accounting either at the inception of the derivative instrument or where hedge accounting was discontinued during the term of the derivative instrument. When the criteria for hedge accounting is not met or when hedge accounting is not elected, realized gains and losses (e.g., cash settlements) and unrealized gains and losses (e.g., non-cash changes in fair value) are recorded in realized and unrealized (gain) loss on derivatives, net in our Statements of Operations. Conversely, cash settlements of derivative instruments accounted for under hedge accounting are recorded as additions to or reductions of sales of oil and natural gas or interest expense, while changes in fair value of derivative instruments are recognized, to the extent the hedge is effective, in AOCL until the hedged item is recognized in earnings. Realized and unrealized (gain) loss on derivatives, net also includes any hedge ineffectiveness on cash flow hedges accounted for under hedge accounting.

During 2009, we entered into commodity derivative instruments for which we did not elect hedge accounting. In addition, effective January 1, 2010, we elected to discontinue hedge accounting for all of our commodity and interest rate derivative instruments for which we had previously elected hedge accounting, and have elected to discontinue all hedge accounting prospectively. Accordingly, beginning January 1, 2010, changes in the fair value of derivative instruments are recognized immediately in net earnings in our Statements of Operations. Cash flows from operating activities are impacted to the extent that actual cash settlements under our derivative instruments result in making or receiving a payment to or from a counterparty, and such cash settlement gains and losses are recorded under the caption realized and unrealized (gain) loss on derivatives, net in our Statements of Operations. See Notes 8 and 9 to the Financial Statements. Also, See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for further details concerning our hedging activities.

Table of Contents

The following table sets forth the cash settlements and non-cash fair value gains and losses recorded in realized and unrealized (gain) loss on derivatives, net:

	Year Ended December 31,		
	2011	2010	2009
	(in thousands)		
Cash receipts payments (receipts):			
Commodity derivatives—oil	$87,747	$7,078	$6,671
Commodity derivatives—natural gas	(10,806)	(8,889)	888
Financial derivatives—interest(1)	—	17,499	—
Total cash payments	$76,941	$15,688	$7,559
Non-cash fair value (gain) loss:			
Commodity derivatives—oil	$(89,478)	$37,440	$—
Commodity derivatives—natural gas	(1,371)	(12,424)	(355)
Financial derivatives—interest(1)	—	(8,857)	—
Total fair value (gain) loss	$(90,849)	$16,159	$(355)
Realized and unrealized (gain) loss on derivatives, net	$(13,908)	$31,847	$7,204

(1) In the fourth quarter of 2010, we terminated certain interest rate derivative instruments for which we had previously elected hedge accounting. The termination resulted in a cash settlement of $10.8 million, offset by a fair value gain of $8.9 million.

During the year ended December 31, 2009, we recorded $0.6 million under the caption realized and unrealized (gain) loss on derivatives, net as a result of ineffectiveness on cash flow hedges.

Settlement of Flying J Bankruptcy

On July 6, 2010, the Joint Plan of Reorganization of Flying J, Inc., Big West of California, LLC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United State Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of our claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, we and Flying J agreed that the total amount owed to us by Flying J for the purchases of our California production and other damages was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010.

Oil and Natural Gas Operating and Other Expenses

The following table presents information about our oil and natural gas operating and other expenses from continuing operations for each of the years ended December 31:

	Amount per BOE			Amount (in thousands)		
	2011	2010	2009	2011	2010	2009
Operating costs—oil and natural gas production	$18.23	$15.95	$14.66	$237,476	$190,218	$156,612
Production taxes	2.58	1.93	1.70	33,617	22,999	18,144
DD&A—oil and natural gas production	16.42	15.05	13.10	213,859	179,432	139,919
G&A	4.74	4.43	4.61	61,727	52,846	49,237
Interest	5.59	5.58	4.67	72,807	66,541	49,923

Total	$47.56	$42.94	$38.74	$619,486	$512,036	$413,835

38

Table of Contents

- Operating costs—oil and natural gas production were $237.5 million in 2011, an increase of $47.3 million, or 25%, from $190.2 million in 2010. On a per BOE basis, operating costs—oil and natural gas production were $18.23 per BOE in 2011, an increase of $2.28 per BOE, or 14%, from $15.95 per BOE in 2010. The increase primarily results from higher steam costs resulting from higher volumes of injected steam, partially offset by a decrease in natural gas fuel cost and increases in water hauling and disposal costs, well maintenance and workover costs, contract labor costs and transportation costs. Operating costs—oil and natural gas production were $190.2 million in 2010, an increase of $33.6 million, or 21%, compared to $156.6 million in 2009. On a per BOE basis, operating costs—oil and natural gas production were $15.95 per BOE in 2010, an increase of $1.29 per BOE, or 9%, from $14.66 per BOE in 2009. The increase was primarily due to higher steam costs resulting from higher volumes of injected steam and higher natural gas fuel costs, higher expenditures for well workovers and higher compression, gathering, and dehydration costs.

Firm transportation costs totaled $21.4 million, $16.2 million and $16.1 million for the years ended December 31, 2011, 2010 and 2009, respectively. The increase in firm transportation costs in 2011 was due primarily to the commencement of Ruby Pipeline operations in July 2011.

The following table presents steam information:

	Year Ended December 31,		
	2011	2010	2009
Average volume of steam injected (Bbl/D)	133,404	116,956	109,153
Fuel gas cost/MMBtu (including transportation)	$4.20	$4.49	$3.86
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	44,235	36,020	30,462

- Production taxes were $33.6 million in 2011, an increase of $10.6 million, or 46%, from $23.0 million in 2010. On a per BOE basis, production taxes were $2.58 per BOE in 2011, an increase of $0.65, or 34%, from $1.93 per BOE in 2010. The increase in production taxes was primarily due to an increase in the assessed ad valorem values attributed to our California properties and an increase in the number of wells outside California, where property taxes are based largely on assessed value per well. Additionally, our severance taxes increased in 2011, largely due to increased commodity prices. Production taxes were $23.0 million in 2010, an increase of $4.9 million, or 27%, from $18.1 million in 2009. On a per BOE basis, production taxes were $1.93 per BOE in 2010, an increase of $0.23 per BOE, or 14%, from $1.70 per BOE in 2009. The increase in production taxes was primarily due to an increase in the assessed ad valorem values attributed to our California properties. In addition, our West Texas and Utah properties contributed to a higher cost per BOE due to severance taxes tied to the field sales price of the commodity.

- Depreciation, depletion and amortization—oil and natural gas production (DD&A—oil and natural gas production) was $213.9 million in 2011, an increase of $34.4 million, or 19%, from $179.4 million in 2010. On a per BOE basis, DD&A—oil and natural gas production was $16.42 per BOE in 2011, an increase of $1.37 per BOE, or 9%, from $15.05 per BOE in 2010. The increase in DD&A—oil and natural gas production per BOE is primarily due to an overall shift in production volumes to our assets outside of California, which have higher drilling and leasehold acquisition costs than our California properties. In 2011, 49% of our production volumes were heavy oil produced in California, compared to 52% of our production volumes in 2010. DD&A—oil and natural gas production was $179.4 million in 2010, an increase of $39.5 million, or 28%, from $139.9 million in 2009. On a per BOE basis, DD&A—oil and natural gas production was $15.05 per BOE in 2010, an increase of $1.95, or 15%, from $13.10 per BOE in 2009. The increase in DD&A—oil and natural gas production per BOE was primarily due to the contribution of our development properties with higher drilling and leasehold acquisition costs than our California properties, including our recent acquisitions in the Permian and a shift in production volumes to assets outside of California.

-

General and administrative expense (G&A) was $61.7 million in 2011, an increase of $8.9 million, or 17%, from $52.8 million in 2010. On a per BOE basis, G&A was $4.74 per BOE in 2011, an increase of $0.31 per BOE, or 7%, from $4.43 per BOE in 2010. The increase is due in part to higher employee salary and benefit costs. As of December 31, 2011, we had 317 full-time employees compared to 270 as of December 31, 2010. The increase in employees was primarily due to our acquisitions in the Permian and additional personnel required for our growing capital program and production levels. Additionally, G&A increased due to higher consulting costs directly attributable to our efforts to comply with new regulations in California, as well as our growing capital program and production levels. G&A was $52.8 million in 2010, an increase of $3.6 million, or 7%, from $49.2 million in 2009. On a per BOE basis, G&A was $4.43 per BOE in 2010, a decreased of $0.18 per BOE, or 4%, from $4.61 per BOE in 2009. The increase was largely

Table of Contents

due to increases in employee compensation, including bonuses, related to increased employees in the Permian and to support increasing production. The decrease in G&A on a per BOE basis was due to increased production.

Interest was $72.8 million in 2011, an increase of $6.3 million, or 9%, from $66.5 million in 2010. The increase in interest is a result the issuance of our 6.75% senior notes due 2020 (2020 Notes) in November 2010 and an increase in the average amount of borrowings outstanding under our credit facility. These increases were partially offset by a decrease in non-cash derivative losses of $7.5 million related to the de-designated interest rate hedges reclassified from AOCL into interest expense and a decrease in interest payments related to the repurchase of $94.7 million aggregate principal amount of our 2014 Notes in September and October of 2011. Interest was $66.5 million in 2010, an increase of $16.6 million, or 33%, compared to $49.9 million in 2009. Interest in 2010 included non-cash derivative losses of $8.3 million related to the de-designated interest rate hedges reclassified from AOCL into interest . In addition, interest increased due to the issuances of our 2014 Notes in May and August of 2009 and our 2020 Notes in November 2010, partially offset by a decrease in the average amount of borrowings outstanding under our credit facility.

Extinguishment of Debt. We recorded debt extinguishment costs of $15.5 million, $0.6 million and $10.8 million in 2011, 2010 and 2009, respectively. In 2011, we wrote off $15.0 million in conjunction with the repurchase of $94.7 million aggregate principal amount of our 2014 Notes, consisting of $11.5 million in premium paid over par and $3.5 million in write-offs of net discount and deferred financing costs. We also wrote off $0.5 million associated with one lender that did not renew its commitment under our credit facility in October 2011. In 2010, we wrote off $0.6 million associated with borrowing base changes under our credit facility. In 2009, we wrote off costs associated with borrowing base changes under our credit facility and fees associated with the extinguishment of our second lien term loan.

Transaction Costs on Acquisitions. In 2010, we incurred $2.6 million of acquisition related expenses for the acquisition of certain properties in the Permian. See Note 2 to the Financial Statements.

Impairment of Oil and Natural Gas Properties. We recorded non-cash impairments of oil and natural gas properties in continuing operations of $625.6 million, $0.0 million, and $1.0 million, in 2011, 2010 and 2009, respectively.

In the fourth quarter of 2011, we recorded a non-cash impairment of $625.0 million related our E. Texas natural gas properties. The impairment was due to decreases in natural gas prices and, as a result, changes in our development plans. In the fourth quarter of 2011, the NYMEX HH five-year future strip (the average of the settlement prices of the next 60 months' futures contracts) decreased approximately 15%. The assets were written down to their estimated fair value. Further, in 2011, 2010 and 2009, we recorded non-cash impairments in continuing operations of $0.6 million, $0 million and $1.0 million related to the expiration of acreage primarily in the Uinta. See Notes 9 and 11 to the Financial Statements.

In 2009, we recorded a non-cash impairment in discontinued operations of $9.6 million related to the sale of our DJ assets. See Note 2 to the Financial Statements.

Dry Hole, Abandonment, Impairment and Exploration. We recorded dry hole, abandonment and impairment charges of $5.2 million, $1.5 million and $4.2 million in 2011, 2010 and 2009, respectively. In 2011, we recorded a $4.3 million impairment charge related to the write-down of three rigs to their fair value. In 2010, we recorded dry hole expense due to a mechanical failure encountered on one well in the Piceance. In 2009, we recorded a $4.2 million impairment charge related to the write-down of a rig to its fair value. See Notes 9 and 11 to the Financial Statements.

We incurred exploration costs in 2011, 2010 and 2009, of $0.1 million, $0.8 million and $0.2 million, respectively. These costs consist primarily of geological and geophysical costs.

Bad Debt (Recovery) Expense. On July 6, 2010, the Joint Plan of Reorganization of Flying J was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the Stipulation, pursuant to which Flying J agreed that the total amount owed to us by Flying J was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010. In 2010, we recorded a settlement of our Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

Income Tax (Benefit) Expense. Our effective income tax rates for the years ended December 31, 2011, 2010, and 2009 were 38%, 40% and 30%, respectively. In 2011, we recorded an income tax benefit due to a pre-tax loss as a result of the impairment of our E. Texas natural gas properties. In 2009, the effective income tax rate was impacted by reduced state rates and a decrease in our liability related to uncertain income tax positions. Our estimated annual effective income tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences (i.e., differences between book earnings and taxable income that are not expected to reverse in future periods). See Note 5 to the Financial Statements.

Estimated 2012 Oil and Natural Gas Operating, G&A and Interest Expense. We estimate our 2012 production volume will range between 38,000 BOE/D and 39,000 BOE/D. Based on WTI of $90.00 and NYMEX HH of $3.00 MMBtu, we expect our oil and natural gas operating and other expenses to be within the following ranges:

	Amount per BOE		
	Anticipated range in 2012	2011	2010
Operating costs—oil and natural gas production	$17.00 - 19.50	$18.23	$15.95
Production taxes	2.50 - 3.25	2.58	1.93
DD&A	15.00 - 18.00	16.42	15.05
G&A	4.25 - 5.50	4.74	4.43
Interest expense	5.50 - 6.25	5.59	5.58
Total	$44.25 - 52.50	$47.56	$42.94

Financial Condition, Liquidity and Capital Resources

Our development, exploitation and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and borrowings under our credit facility as our primary sources of liquidity. The debt and equity capital markets have served as our primary source of financing to fund large acquisitions and other transactions. Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control. We have also engaged in asset monetization transactions as a source of financing, as market conditions have permitted. In April 2009, we sold our assets in the DJ for $139.8 million, and in July 2009 we completed the sale of our E. Texas natural gas gathering system for $18.4 million. As we pursue profitable reserves and production growth, we continually monitor the capital resources, including the issuance of equity and debt securities, available to us to meet our future financial obligations, planned capital expenditure activity and liquidity.

At December 31, 2011, we had a working capital deficit of approximately $63.5 million. We generally maintain a working capital deficit because we use excess cash to reduce outstanding borrowings under our credit facility. Our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flows. As of December 31, 2011, we had hedged approximately 70% and 40% of our expected oil production in 2012 and 2013 in the form of swaps and collars. This level of derivatives is expected to provide a measure of certainty of the cash flows that we will receive for a portion of our production in 2012 and 2013. In the future, we may increase or decrease our derivative positions. At December 31, 2011, all of our derivatives counterparties were commercial banks that are parties, or affiliates of parties, to our credit facility. See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for further details concerning our hedging activities.

Table of Contents

Revolving Credit Facility. Our senior secured revolving credit facility, which matures in May 2016, has a current borrowing base of $1.4 billion, subject to lender commitments. On October 26, 2011, as part of the semi-annual borrowing base redetermination process, we entered into an amendment to the credit facility which, among other things, increased total lender commitments to $1.2 billion. Borrowings under our credit facility bear interest at either (i) LIBOR plus a margin between 1.50% and 2.50% or (ii) the prime rate plus a margin between 0.50% and 1.50%, in each case, based on the amount utilized. The annual commitment fee on the unused portion of the credit facility ranges between 0.35% to 0.50% based on the amount utilized.

As of December 31, 2011, outstanding borrowings under the facility were $531.5 million (excluding $23.2 million of outstanding letters of credit), leaving $645.3 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of our proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. We and the lenders each of a right to one additional redetermination each year.

The credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. The facility also contains other customary covenants, subject to certain agreed exceptions, including covenants restricting our ability to, among other things, owe or be liable for indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of our material assets or properties; declare dividends on or redeem or repurchase our capital stock; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; engage in transactions with affiliates; and enter into, create or allow to exist contractual obligations limiting our ability to grant liens on our assets to the lenders under the senior secured revolving credit facility. We are currently in compliance with all financial covenants and have complied with all financial covenants for each of the years ended December 31, 2010 and 2009.

Subject to certain agreed limitations, we granted first priority security interests over substantially all of our assets in favor of the lenders under the senior secured revolving credit facility.

Money Market Line of Credit. Our senior secured uncommitted money market line of credit has a borrowing capacity of up to $40 million for a maximum of 30 days. As of December 31, 2011, there were no borrowings outstanding under the money market line of credit. Amounts borrowed under the money market line of credit bear interest at LIBOR plus a margin of approximately 1.4%. The line of credit is not currently unavailable to us and we do not know when or if the line of credit will be available in the future.

Other Outstanding Indebtedness. As of December 31, 2011, in addition to our credit facility, we had the following long-term debt outstanding:

- $200 million aggregate principal amount of our 8.25% senior subordinated notes due 2016 (2016 Notes);
- $355.3 million aggregate principal amount of our 2014 Notes; and
- $300 million aggregate principal amount of our 2020 Notes.

The indentures governing our senior and subordinated notes contain provisions that limit our ability to incur, assume or guarantee additional indebtedness; issue redeemable stock and preferred stock; pay dividends or distributions or redeem or repurchase capital stock; prepay, redeem or repurchase debt that is junior in right of payment to our senior and subordinated notes; make loans and other types of investments; incur liens; restrict dividends, loans or asset transfers from our subsidiaries; sell or otherwise dispose of assets, including capital stock of subsidiaries; consolidate or merge with or into, or sell substantially all of our assets to, another person; enter into transactions with affiliates;

and enter into new lines of business. Upon specified change in control events, we will be required to make offers to repurchase our senior and subordinated notes at amounts specified in the indentures governing such notes.

From August to October 2011, we repurchased $94.7 million aggregate principal amount of our 2014 Notes for an aggregate purchase price of $108.8 million, including accrued and unpaid interest. These notes were repurchased using available borrowings under our credit facility. We may from time to time seek to repurchase our outstanding notes, including additional 2014 Notes, through open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts repurchased may be material.

Credit Ratings. Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate our outstanding notes and have assigned us a credit rating. We do not have any provisions that are linked to our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our currently outstanding debt. However, our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Historical Cash Flows. Cash flows provided by operating activities are primarily affected by the price of oil and natural gas, sales volumes and changes in working capital. The increase in net cash provided by operating activities of $88.7 million in 2011 compared to 2010 is primarily due to a 28% increase in average commodity sales prices and a 10% increase in sales volume. The increase in net cash provided by operating activities of $154.7 million in 2010 compared to 2009 is primarily due to a 12% increase in average commodity sales prices and a 11% increase in sales volume.

Cash flows used by investing activities are primarily comprised of development, exploitation and acquisition of oil and natural gas properties net of dispositions of oil and natural gas properties. The increase in net cash used in investing activities of $38.2 million in 2011 compared to 2010 is due to an increase in development expenditures offset by a decrease in expenditures for property acquisitions in 2011 as compared with 2010. The increase in net cash used in investing activities of $634.1 million in 2010 compared to 2009 is due to an increase in development expenditures and an increase in acquisition activities in 2010 compared with 2009.

Net cash provided by financing activities in 2011 includes net borrowings under our credit facility of $361.5 million, partially offset by the repurchase of $94.7 million aggregate principal amount of our 2014 Notes. Net cash provided by financing activities in 2010 included net proceeds of $224.0 million from the issuance of 8 million shares of our Class A Common Stock and $300.0 million aggregate principal amount of our 2020 Notes, partially offset by debt issuance costs of $15.2 million and net repayment of our outstanding borrowings under our credit facility and our money market line of credit of $196.7 million. Net cash used in financing activities in 2009 included $585.1 million net repayment on our outstanding borrowings under our credit facility and money market line of credit and $24.0 million of debt issuance costs, partially offset by the issuance of $450.0 million aggregate principal amount of our 2014 Notes for net proceeds of $435.0 million after underwriting discounts and estimated offering expenses.

Capital Expenditures. The following is a summary of the drilling and development capital expenditures:

(in thousands)	Year Ended December 31,		
Asset Team	2011	2010	2009
S. Midway	$47,000	$35,000	$24,000
N. Midway	156,000	67,000	32,000
Permian	218,000	42,000	—
Uinta	63,000	50,000	6,000
E. Texas	11,000	71,000	47,000
Piceance	31,000	45,000	26,000
Corporate	1,000	—	—
Total	$527,000	$310,000	$135,000

We continually evaluate our capital needs and compare them to our capital resources. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. We expect our 2012 capital budget to be between $600 million and $650 million, assuming an average commodity price of $90 WTI, and we expect to fund our 2012 capital budget largely with net cash provided by our operating activities. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we may adjust our capital budget accordingly or adjust borrowings under our credit facility, as needed. Substantially all of our 2012 capital expenditure budget is directed towards our oil assets, targeting oil production growth of approximately 20%.

Although we have no specific budget for property acquisitions in 2012, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that, should attractive acquisition opportunities be presented, we will be able to finance additional capital expenditures with cash flows from operating activities, borrowings under our credit facility, issuances of additional debt or equity, or agreements with industry partners.

Table of Contents

Contractual Obligations

Our contractual obligations as of December 31, 2011 are as follows:

(in millions)	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt and interest(1)	$1,780.2	$83.9	$83.9	$417.9	$47.5	$769.4	$377.6
Asset retirement obligations(2)	64.0	4.7	3.8	3.6	3.6	3.6	44.7
Operating leases(3)	11.8	2.8	2.8	2.6	2.2	1.4	—
Other commitments (4)	31.3	14.2	11.4	1.8	1.9	2.0	—
Drilling rig commitments(5)	7.0	7.0	—	—	—	—	—
Firm natural gas transportation contracts(6)	263.5	29.7	30.2	32.7	32.6	32.5	105.8
Derivative liabilities(7)	35.9	20.4	15.5	—	—	—	—
Total	$2,193.7	$162.7	$147.6	$458.6	$87.8	$808.9	$528.1

(1) Long-term debt consists of our 2016 Notes, 2014 Notes, 2020 Notes and outstanding debt under our credit facility, and assumes no principal repayment until the due date of the instruments. Cash interest expense on our credit facility is estimated assuming no principal repayment until the instrument due date and is estimated at a constant interest rate of 2.018%.

(2) The ultimate settlement amounts and the timing of the settlement of such obligations are unknown because they are subject to, among other things, federal, state, local, and tribal regulation and economic factors. See Part II, Item 7A. "Critical Accounting Policies and Estimates" for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

(3) Operating leases relate primarily to obligations associated with our office facilities, equipment, vehicles and aircraft.

(4) Other commitments relate primarily to natural gas purchases, cogeneration facility management services and equipment rentals.

(5) We currently have four drilling rigs under contract that require minimum payments for the full contract term or penalties upon early termination. All these drilling rig contracts expire in 2012. Contracts for all other rigs performing work for us at December 31, 2011 were on a well-by-well basis and could be released without penalty at the conclusion of drilling on the current well, and therefore have not been included in the table above.

(6) We enter into certain firm commitments to transport natural gas production to market and to transport natural gas for use in our cogeneration and conventional steam generation facilities. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity is used or not. These commitments include a transportation agreement with Questar Pipeline Company for an average of 6,200 MMBtu/D of firm transportation over a period of eight years, based on the expectation that the expansion of the Chipeta Processing LLC natural gas plant will be completed and transportation under this contract will begin July 1, 2012.

(7) Derivative liabilities represent the fair value of our derivatives presented as net liabilities in our Balance Sheets as of December 31, 2011. These amounts represent open commodity derivative instruments that were in a net liability position with the counterparty at December 31, 2011. Our remaining commodity derivative instruments were in a net asset position with the counterparty at December 31, 2011. The ultimate settlement amounts of our derivative liabilities are unknown because they are subject to continuing market fluctuations. See Notes 8 and 9 to the Financial Statements. Also, See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for further details concerning our hedging activities.

Based on current oil and natural gas prices and anticipated levels of production, we believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs, dividend distributions and debt repayments; while complying with our debt covenants and meeting any other obligations that may arise from our oil and natural gas operations. However, if our revenue and cash flow decrease in the future as a result of a deterioration in domestic and global economic conditions or a significant decline in commodity prices, we may elect to reduce our planned capital expenditures. We believe that this financial flexibility to adjust our spending levels will provide us with sufficient liquidity to meet our financial obligations. See Part I, Item 1A—"Risk Factors," for a discussion of the risks and uncertainties that affect our financial condition, results of operation, and operating cash flows.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses and to disclose contingent assets and liabilities at the date of our financial statements. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note 1 to our Financial Statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Successful Efforts Method of Accounting. We account for our oil and natural gas exploration and development costs using the successful efforts method. Geological and geophysical costs 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 costs of development wells are capitalized whether productive or nonproductive.

Impairment of Oil and Natural Gas Properties. Proved oil and natural gas properties are reviewed for impairment on a field-by-field basis, annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and natural gas properties and compare these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, and discount rates commensurate with the risk associated with realizing the projected cash flows. Due to the impact of lower natural gas prices, we recorded an impairment of $625.0 million related to our E. Texas natural gas assets. See Notes 9 and 11 to the Financial Statements.

Unproved oil and natural gas properties are periodically assessed for impairment on a project-by-project basis. The impairment assessment is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognize an impairment loss at that time.

Oil and Natural Gas Reserves. Estimated proved reserves included in this Annual Report on Form 10-K were prepared by DeGolyer and MacNaughton (D&M), an independent petroleum engineering consulting firm that has provided consulting services throughout the world for over 70 years. Estimated proved reserves presented in this report are calculated in accordance with the SEC's "Modernization of Oil and Gas Reporting" rule which was first effective for December 31, 2009 reporting. These rules include calculating estimated proved reserves based on the average prices during the twelve-month period prior to the reporting date, with such prices determined as the unweighted arithmetic average of the first-day-of-the month prices for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition to the physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, economic factors such as changes in commodity prices or development and production expenses, may require revision of such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates. See Part I, Item 1A—"Risk Factors," for a description of some of the risks and uncertainties associated with our business and reserves.

Depreciation, Depletion and Amortization (DD&A-oil and natural gas production). The provision for DD&A-oil and natural gas production is calculated on a field-by-field basis using the unit-of-production method. Projected future production rates, the timing of future capital expenditures as well as changes in commodity prices, may significantly impact estimated reserve quantities. DD&A—oil and natural gas production is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. 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 oil and natural gas production, which in turn reduces net earnings. Changes in reserve estimates are applied on a prospective basis. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher costs fields.

Capitalized Interest. Acquisition costs of proved undeveloped and unproved properties qualify for interest capitalization during a period if interest cost is incurred and activities necessary to bring the properties into a productive state are in progress. As wells are drilled in a field with proved undeveloped or unproved reserves, a portion of the acquisition costs are either re-designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, we determine the amount of the acquisition cost to re-designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

Purchase Price Allocations. We occasionally acquire assets and assume liabilities in transactions accounted for as business combinations. In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. Any excess of amounts assigned to assets and liabilities over the purchase price is recorded as a gain on bargain purchase. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on management’s expectations of future recoverable proved and risk-adjusted probable reserves, commodity prices based on commodity futures price strips, production timing, drilling and production costs and a risk-adjusted discount rate.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A-oil and natural gas production, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We also enter into derivative contracts to mitigate the risk of interest rate fluctuations. The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in accumulated other comprehensive loss until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the statements of operations because changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings. The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, whether or not the forecasted hedged transaction will occur, option pricing models, futures prices, volatility, and time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. Effective January 1, 2010, we elected to de-designate all of our commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively.

Due to the volatility of oil and natural gas prices and interest rates, the estimated fair values of our derivative instruments are subject to large fluctuations from period to period. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk" for a sensitivity analysis of the change in net fair values of our commodity and interest rate derivatives based on a hypothetical change in commodity prices and interest rates.

Income Taxes and Uncertain Tax Positions. Income taxes are recorded for the income tax effects of transactions reported in the financial statements and consist of income taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are also recognized for income tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted income tax rates to the differences between the financial statements and income tax reporting. We routinely assess the realizability of our deferred income tax assets, and a valuation allowance is recognized if it is determined that deferred income tax assets may not be fully utilized in future periods. We consider future taxable earnings in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable earnings, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). There can be no assurance that facts and circumstances will not materially change and require us to establish deferred income tax asset valuation allowances in a future period. We are subject to taxation in many jurisdictions, and the calculation of our income tax liabilities involves dealing with uncertainties in the application of complex income tax laws and regulations in various taxing jurisdictions. We recognize certain income tax positions that meet a more-likely-than not recognition threshold. If we ultimately determine that the payment of these liabilities will be unnecessary, we will reverse the liability and recognize an income tax benefit during the period in which we determine the liability no longer applies.

Asset Retirement Obligations. Our asset retirement obligations (AROs) consist primarily of estimated future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of the ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted-risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net earnings as accretion expense. The related capital cost, including revisions thereto, is charged to expense through DD&A-oil and natural gas over the life of the oil and natural gas field.

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. 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 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 natural gas operating costs and the liability, if applicable, recorded on our Balance Sheets.

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 natural 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. A portion of the capital costs of the cogeneration facilities is allocated to DD&A—oil and natural gas production.

Impact of Recently Issued Accounting Standard Updates

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, see Note 1 to the Financial Statements.

Table of Contents

Reconciliation of Non-GAAP Measures

Discretionary Cash Flow. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items. Management uses discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. The following table provides a reconciliation of discretionary cash flow to cash provided by operating activities, the most directly comparable GAAP measure, for the period presented.

	Year Ended December 31:		
(in millions)	2011	2010	2009
Net cash provided by operating activities	$455.9	$367.2	$212.6
Add back: Net increase (decrease) in current assets	26.3	(12.5)	10.1
Add back: Net decrease (increase) in current liabilities including book overdraft	(20.3)	(12.7)	33.6
Add back: Unwind interest swap payments	—	10.8	—
Add back: Recovery of Flying J bad debt	—	38.5	—
Discretionary cash flow	$461.9	$391.3	$256.3

Operating Margin per BOE. Operating margin per barrel consists of oil and natural gas revenues less oil and natural gas operating expenses and production taxes divided by the total barrels sold during the period. Management uses operating margin per barrel as a measure of profitability and believes it provides useful information to investors because it relates our oil and natural gas revenue and oil and natural gas operating expenses to our total units of production providing a gross margin per unit of production, allowing investors to evaluate how our profitability varies on a per unit basis each period.

	Year Ended December 31:		
(per BOE)	2011	2010	2009
Average sales price including cash derivative settlements	$65.68	$53.84	$46.02
Average operating costs—oil and natural gas production	18.23	15.95	14.66
Average production taxes	2.58	1.93	1.70
Average operating margin	$44.87	$35.96	$29.66

Pre-Tax PV10. Pre-tax PV10 is defined as standardized measure of discounted future net cash flows before the effect of income taxes. We present pre-tax PV-10 because it is a widely used industry standard which management believes is useful when comparing our asset base and performance to other comparable oil and natural gas exploration and production companies. The following table reconciles pre-tax PV-10 to the standardized measure of discounted future net cash flows:

	Year Ended December 31,	
(in thousands)	2011	2010
Standardized measure of oil and gas	$4,035,279	$2,799,156
Discounted future cash flow from income taxes	1,669,768	1,035,021
Discounted future net cash flow before income taxes	$5,705,047	$3,834,177

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our primary market risk relates to the prices we receive for our oil and natural gas production. Historically the markets for oil and natural gas have been volatile and are likely to continue to be volatile in the future. We use various derivative instruments to manage our exposure to commodity price risk. All derivative instruments are recorded on the balance sheet at fair value. If a derivative instrument does not qualify for hedge accounting or we do not elect to use hedge accounting, the changes in fair value, both realized and unrealized, are recorded as unrealized gains or losses in realized and unrealized (gain) loss on derivatives, net in our Statements of Operations. Cash flows from operating activities are impacted to the extent that actual cash settlements under these derivative instruments result in payments to or from the counterparty, and such cash settlement gains and losses are recorded under realized and unrealized (gain) loss on derivatives, net in our Statements of Operations. See Notes 8 and 9 to the Financial Statements. We do not have any current derivative instruments for which we have elected hedge accounting.

Currently, our derivative instruments are in the form of swaps and collars. However, we may use a variety of derivative instruments in the future to hedge WTI or other index prices. A two-way collar is a combination of options, a sold call and purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options, a sold call, a purchased put and a sold put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. We utilize costless collars which are options positions by which the proceeds from the sale of the call option fund the purchase of a put option. A hypothetical $10 increase in the oil prices used and $1 increase in the natural gas prices used to calculate the fair values of our derivative instruments at December 31, 2011 would decrease the respective fair value of crude oil and natural gas derivative instruments at December 31, 2011 by $96.9 million and $3.3 million, respectively. A hypothetical $10 decrease in oil prices and a $1 decrease in natural gas prices used to calculate the fair values of our derivative instruments at December 31, 2011 would increase the respective fair value of oil and natural gas derivative instruments at December 31, 2011 by $83.1 million and $3.3 million, respectively. As our natural gas production continues to decrease and our use of natural gas for steaming operations increase, we may become a net consumer of natural gas and may enter into derivative instruments to limit our exposure to future increases in natural gas prices.

Table of Contents

The following table summarizes our commodity hedge positions as of December 31, 2011:

Term	Average Barrels Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2012	1,000	$65.00/$85.00/$97.25
Full year 2012	1,000	$70.00/$87.00/$105.00
Full year 2012	1,000	$70.00/$88.00/$106.00
Full year 2012	1,000	$60.00/$80.00/$96.92
Full year 2012	1,000	$60.00/$80.00/$120.00
Full year 2012	1,000	$70.00/$88.15/$100.00
Full year 2012	1,000	$70.00/$86.85/$100.00
Full year 2012	1,000	$69.70/$85.00/$100.00
Full year 2012	1,000	$70.00/$87.00/$108.50
Full year 2012	1,000	$70.00/$90.00/$116.50
Full year 2012	1,000	$70.00/$90.00/$120.00
Full year 2012	1,000	$70.00/$95.00/$120.10
Full year 2012	1,000	$77.95/$105.00/$115.00
Full year 2012	1,000	$80.00/$107.00/$119.60
Full year 2012	500	$70.00/$90.00/$100.00
Full year 2012	500	$70.00/$90.00/$100.00
Full year 2012	1,000	$75.00/$90.00/$101.85
Full year 2012 (1)	1,000	$70.00/$85.00/$92.00
Full year 2012 (1)	2,000	$70.00/$80.00/$83.00
Full year 2012 (1)	1,500	$75.00/$90.00/$97.50
Full year 2012 (1)	500	$75.00/$90.00/$106.90
Full year 2013	1,000	$65.00/$85.00/$97.25
Full year 2013	1,000	$70.00/$87.00/$105.00
Full year 2013	1,000	$70.00/$88.00/$106.00
Full year 2013	1,000	$60.00/$80.00/$103.30
Full year 2013	1,000	$70.00/$88.15/$100.00
Full year 2013	1,000	$70.00/$86.85/$100.00
Full year 2013	1,000	$69.70/$85.00/$100.00
Full year 2013	1,000	$70.00/$87.00/$108.50
Full year 2013	1,000	$70.00/$90.00/$116.50
Full year 2013	1,000	$70.00/$90.00/$120.00
Full year 2013	1,000	$70.00/$95.00/$120.10
Full year 2013	1,000	$77.95/$105.00/$115.00
Full year 2013	1,000	$80.00/$107.00/$119.60
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	1,000	$75.00/$90.00/$101.85
Full year 2014	1,000	$77.95/$105.00/$115.00
Full year 2014	1,000	$80.00/$107.00/$119.60

Term	Average MMBtu Per Day	Average Prices
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2012	5,000	$7.16
Full year 2012	5,000	$5.75
Natural Gas Sales (NYMEX HH) Collars		
Full year 2012	5,000	$6.00/$7.70
Natural Gas Sales (NYMEX HH to NGPL-Tex OK) Basis Swaps		
Full year 2012	2,500	$0.44
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2012	2,500	$0.32

(1)

In the third quarter of 2011, we converted several of our two-way oil collars to three-way oil collars. There were no payments made or received as a result of these transactions.

Excluded from the table above are our calendar month average swaps, which protect us from variances in market pricing conditions of certain of our sales contracts. These derivative contracts protect 5,000 BOE/D of our Permian sales volumes and have differentials of $0.075 to $0.080 during 2012 and $0.070 to $0.075 during 2013.

Table of Contents

Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit facility. Our credit facility allows us to fix the interest rate for all or a portion of the principal balance for a period up to 12 months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt. At December 31, 2011, our outstanding principal balance under our credit facility was $531.5 million and the weighted average interest rate on the outstanding principal balance was 2.018%. At December 31, 2011, the carrying amount approximated fair market value. Assuming a constant debt level of $1.4 billion, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $3.3 million over a 12-month time period.

Table of Contents

Item 8. Financial Statements and Supplementary Data

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

Table of Contents

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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 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, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 8 to the financial statements, the Company discontinued hedge accounting effective January 1, 2010.

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 28, 2012

53

Table of Contents

BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2011 and 2010
(In Thousands, Except Share Information)

	2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	$298	$278
Short-term investments	65	65
Accounts receivable	115,952	93,406
Deferred income taxes	13,779	32,342
Derivative instruments	6,117	2,742
Assets held for sale	14,622	—
Prepaid expenses and other	16,801	14,033
Total current assets	167,634	142,866
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	2,531,393	2,655,792
Derivative instruments	7,027	2,054
Other assets	28,898	37,904
	$2,734,952	$2,838,616
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$126,489	$106,459
Revenue and royalties payable	49,253	37,812
Accrued liabilities	35,066	36,234
Line of credit	—	5,300
Derivative instruments	20,365	84,846
Total current liabilities	231,173	270,651
Long-term liabilities:		
Deferred income taxes	185,450	329,207
Senior secured revolving credit facility	531,500	170,000
8.25% Senior subordinated notes due 2016	200,000	200,000
10.25% Senior notes due 2014, net of unamortized discount of $6,564 and $11,035, respectively	348,692	438,965
6.75% Senior notes due 2020	300,000	300,000
Asset retirement obligations	64,019	53,443
Derivative instruments	15,505	33,526
Other long-term liabilities	17,884	18,271
	1,663,050	1,543,412
Commitments and contingencies (Note 10)		
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; 52,067,994 and 51,426,232 shares issued and outstanding, respectively	521	514
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $0.50 per share)	18	18
Capital in excess of par value	350,158	327,369
Accumulated other comprehensive loss	(5,517)	(43,806)

Retained earnings	495,549	740,458
Total shareholders' equity	840,729	1,024,553
	$2,734,952	$2,838,616

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

54

Table of Contents

BERRY PETROLEUM COMPANY
Statements of Operations
Years ended December 31, 2011, 2010 and 2009
(In Thousands, Except Per Share Data)

	2011	2010	2009
REVENUES			
Sales of oil and natural gas	$870,773	$619,608	$500,532
Sales of electricity	34,953	34,740	36,065
Natural gas marketing	13,832	22,162	22,806
Settlement of Flying J bankruptcy claim	—	21,992	—
Gain on sale of assets	—	—	826
Interest and other income, net	1,784	3,300	1,810
	921,342	701,802	562,039
EXPENSES			
Operating costs—oil and natural gas production	237,476	190,218	156,612
Operating costs—electricity generation	25,690	31,295	31,400
Production taxes	33,617	22,999	18,144
Depreciation, depletion & amortization—oil and natural gas production	213,859	179,432	139,919
Depreciation, depletion & amortization—electricity generation	1,963	3,225	3,681
Natural gas marketing	13,038	19,896	21,231
General and administrative	61,727	52,846	49,237
Interest	72,807	66,541	49,923
Extinguishment of debt	15,544	573	10,823
Realized and unrealized (gain) loss on derivatives, net	(13,908)	31,847	7,756
Gain on purchase	(1,046)	—	—
Transaction costs on acquisitions	—	2,635	—
Impairment of oil and natural gas properties	625,564	—	1,017
Dry hole, abandonment, impairment and exploration	5,302	2,311	4,408
Bad debt recovery	—	(38,508)	—
	1,291,633	565,310	494,151
(Loss) earnings from continuing operations before income taxes	(370,291)	136,492	67,888
Income tax (benefit) provision	(142,228)	53,968	20,664
Net (loss) earnings from continuing operations	(228,063)	82,524	47,224
Net earnings from discontinued operations	—	—	6,806
Net (loss) earnings	$(228,063)	$82,524	$54,030
Basic net (loss) earnings per share from continuing operations	(4.21)	1.54	1.03
Basic net earnings per share from discontinued operations	—	—	0.15
Basic net (loss) earnings per share	$(4.21)	$1.54	$1.18
Diluted net (loss) earnings per share from continuing operations	(4.21)	1.52	1.02
Diluted net earnings per share from discontinued operations	—	—	0.15
Diluted net (loss) earnings per share	$(4.21)	$1.52	$1.17
Dividends per share	$0.31	$0.30	$0.30

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

55

Table of Contents

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2011, 2010 and 2009
(In Thousands)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balances at January 1, 2009	$427	$18	$79,653	$633,749	$ 113,697	$827,544
Stock options and restricted stock issued	3	—	890	—	—	893
Stock based compensation expense	—	—	8,623	—	—	8,623
Income tax effect of stock option exercises	—	—	(98)	—	—	(98)
Dividends ($0.30 per share)	—	—	—	(13,664)	—	(13,664)
Comprehensive earnings:						
Net earnings	—	—	—	54,030	—	54,030
Effect of derivative instruments, net of income taxes	—	—	—	—	(174,069)	(174,069)
Total comprehensive loss	—	—	—	—	—	(120,039)
Balances at December 31, 2009	430	18	89,068	674,115	(60,372)	703,259
Issuance of stock	80		224,233			224,313
Stock options and restricted stock issued	4	—	4,398	—	—	4,402
Stock based compensation expense	—	—	9,386	—	—	9,386
Income tax effect of stock option exercises	—	—	284	—	—	284
Dividends ($0.30 per share)	—	—	—	(16,181)	—	(16,181)
Comprehensive earnings:						
Net earnings	—	—	—	82,524	—	82,524
Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	16,566	16,566
Total comprehensive earnings	—	—	—	—	—	99,090
Balances at December 31, 2010	514	18	327,369	740,458	(43,806)	1,024,553
Stock options and restricted stock issued	7	—	10,106	—	—	10,113
Stock based compensation expense	—	—	9,636	—	—	9,636
Income tax effect of stock option exercises	—	—	3,047	—	—	3,047
Dividends ($0.31 per share)	—	—	—	(16,846)	—	(16,846)
Comprehensive earnings:						—
Net (loss)	—	—	—	(228,063)	—	(228,063)
Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	38,289	38,289

Total comprehensive loss	—	—	—	—	—	(189,774)
Balances at December 31, 2011	$521	$18	$350,158	$495,549	$ (5,517)	$840,729

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

56

BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2011, 2010 and 2009
(In Thousands)

	2011	2010	2009
Cash flows from operating activities:			
Net (loss) earnings	$(228,063)	$82,524	$54,030
Depreciation, depletion and amortization	215,822	182,657	145,788
Gain on purchase	(1,046)	—	—
Extinguishment of debt	4,072	573	10,823
Amortization of debt issuance costs and net discount	8,243	8,481	6,827
Impairment of oil and natural gas properties	625,564	—	10,654
Dry hole and impairment	4,616	1,478	4,205
Derivatives	(29,094)	42,609	247
Stock-based compensation expense	9,636	9,386	8,626
Deferred income taxes	(149,279)	54,698	19,998
Loss on sale of asset	—	—	79
Other, net	3,223	(12)	(4,016)
Cash paid for abandonment	(1,803)	(1,832)	(1,030)
Bad debt recovery	—	(38,508)	—
Change in book overdraft	(156)	528	(16,018)
Changes in operating assets and liabilities:			
Accounts receivable	(23,526)	20,055	(11,816)
Inventories, prepaid expenses, and other current assets	(2,768)	(7,553)	1,761
Accounts payable and revenue and royalties payable	25,019	5,273	(49,119)
Accrued interest and other accrued liabilities	(4,561)	6,880	31,537
Net cash provided by operating activities	455,899	367,237	212,576
Cash flows from investing activities:			
Exploration and development of oil and natural gas properties	(527,112)	(310,139)	(134,946)
Property acquisitions	(158,090)	(334,409)	(13,497)
Capitalized interest	(29,117)	(28,321)	(30,107)
Proceeds from sale of assets	—	—	139,796
Deposits on asset sales	3,300	—	—
Net cash used in investing activities	(711,019)	(672,869)	(38,754)
Cash flows from financing activities:			
Proceeds from issuances on line of credit	406,600	316,000	387,700
Payments on line of credit	(411,900)	(310,700)	(413,000)
Proceeds from issuance of 10.25% senior notes due 2014	—	—	434,962
Proceeds from issuance of 6.75% senior notes due 2020	—	300,000	—
Repurchase of 10.25% senior notes due 2014	(94,744)	—	—
Proceeds from long-term borrowings under credit facility	719,700	363,000	655,300
Repayments of long-term borrowings under credit facility	(358,200)	(565,000)	(1,215,100)
Financing obligation	(380)	(346)	18,214
Debt issuance costs	(2,250)	(15,173)	(23,955)
Dividends paid	(16,846)	(16,181)	(13,664)
Proceeds from issuance of stock	—	224,313	—
Proceeds from stock option exercises	10,113	4,402	890
Excess income tax benefit (expense)	3,047	284	(98)

Net cash provided by (used in) financing activities	255,140	300,599	(168,751)
Net increase (decrease) in cash and cash equivalents	20	(5,033)	5,071
Cash and cash equivalents at beginning of year	278	5,311	240
Cash and cash equivalents at end of year	$298	$278	$5,311
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest	$59,853	40,773	36,854
Income taxes paid (refunded)	7,914	(285)	8,769
Noncash investing activities:			
Accrued capital expenditures	$61,098	$51,095	$5,059
Asset retirement obligations	7,448	3,721	1,407

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

57

Table of Contents

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

1. Summary of Significant Accounting Policies

Description of the Business

Berry Petroleum Company (the Company) is an independent energy company engaged in the production, development, exploitation and acquisition of oil and natural gas. The Company has invested in cogeneration facilities, which provide steam required for the extraction of heavy oil and which generate electricity for sale.

Basis of Presentation

These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). Certain amounts in prior years' financial statements have been reclassified to conform to the 2011 financial statement presentation.

Assumptions, Judgments, and Estimates

In the course of preparing the financial statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts previously established.

The more significant areas requiring the use of assumptions, judgments, and estimates include: (1) oil and natural gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) income taxes; (7) valuation of derivative instruments; and (8) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with a remaining maturity of three months or less to be cash equivalents. The Company's cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at December 31, 2011 and 2010 is $16.1 million and $16.3 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Accounts Receivable

Trade accounts receivable consist mainly of receivables from oil and natural gas purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, oil and natural gas receivables are collected within two months.

Bad Debt Recovery

The Company recognized $38.5 million in bad debt expense in the year ended December 31, 2008 related to the Flying J bankruptcy. On July 6, 2010, the Joint Plan of Reorganization of Flying J was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J regarding the resolution of the Company's claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, Flying J agreed that the total amount owed to the Company by Flying J was $60.5 million and, as a result, the Company received $60.5 million in cash on July 23, 2010. In the quarter ended September 30, 2010, the Company recorded a settlement of the Company's Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

Table of Contents

BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

Discontinued Operations

In 2009, the Company sold its DJ assets, the results of operations of which are reported as discontinued operations in the 2009 Statements of Operations. See Note 2 to the Financial Statements.

Income Taxes and Uncertain Tax Positions

The Company recognizes deferred income tax liabilities and assets for the expected future income tax consequences of temporary differences between financial accounting bases and income tax bases of assets and liabilities. Deferred income taxes are measured by applying currently enacted income tax rates. The Company accounts for uncertainty in income taxes for income tax positions taken or expected to be taken in an income tax return. Only income tax positions that meet the more-likely-than-not recognition threshold will be recognized.

Derivative Instruments

The Company enters into derivative contracts, primarily swaps and collars, to manage its exposure to commodity price risk. All derivative instruments, other than those that meet the "normal purchases normal sales" exclusion, are recorded on the balance sheet as either an asset or liability measured at fair value. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. The Company is required to formally document, at the inception of a hedge, the hedging relationship and the risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the method that will be used to assess effectiveness and the method that will be used to measure hedge ineffectiveness of derivative instruments that receive hedge accounting treatment. Effective January 1, 2010, the Company elected to discontinue all hedge accounting prospectively. As a result, subsequent to December 31, 2009, the Company records all derivative instruments as either assets or liabilities at fair value and recognizes all gains and losses from changes in derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive loss (AOCL). See Notes 8 and 9 to the Financial Statements. Cash settlements of derivative instruments used to manage commodity price risk are classified as cash flows from operating activities in the Statements of Cash Flows along with the cash flows from the related oil and natural gas production activities. The Company nets derivative assets and liabilities of a given counterparty whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract. The Company uses these agreements to manage and reduce its potential counterparty credit risk. The Company does not enter into derivative instruments for speculative or trading purposes.

Oil and Natural Gas Properties, Buildings and Equipment

The Company accounts for its oil and natural gas exploration and development costs using the successful efforts method. Geological and geophysical costs are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion, and the related capitalized costs are reviewed quarterly. Exploratory wells that discover potentially economic reserves 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 finds a sufficient quantity of reserves to justify its completion as a producing well and the Company is 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.

The provision for depletion of oil and natural gas properties is calculated on a field-by-field basis using the unit-of-production method. If the estimates of total proved or proved developed reserves decline, the rate at which the Company records depreciation, depletion and amortization (DD&A) expense increases, which in turn reduces net earnings. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. The Company is unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of its development program, as well as future economic conditions. Changes in reserves are applied on a prospective basis.

Buildings and equipment are recorded at cost. Depreciation is calculated 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.

Table of Contents

Capitalized Interest

Acquisition costs of proved undeveloped and unproved properties qualify for interest capitalization during a period if interest cost is incurred and activities necessary to bring the properties into a productive state are in progress. As wells are drilled in a field with proved undeveloped reserves or unproved reserves, a portion of the acquisition costs are either re-designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, the Company determines the amount of the acquisition cost to re-designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

Impairment of Proved and Unproved Properties

Proved oil and natural gas properties are reviewed for impairment on a field-by-field basis, annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. The Company estimates the expected future cash flows of its oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, and discount rates commensurate with the risk associated with realizing the projected cash flows. Due to the impact of lower natural gas prices, the Company recorded an impairment of $625.0 million related to its E. Texas natural gas assets. See Notes 9 and 11 to the Financial Statements.

Unproved oil and natural gas properties are periodically assessed for impairment on a project-by-project basis. The impairment assessment is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize an impairment loss at that time.

Assets Held for Sale

Any properties held for sale as of the date of presentation of the balance sheets have been classified as assets held for sale and are separately presented on the balance sheets at the lower of net book value or fair value less the cost to sell. See Note 3 to the Financial Statements.

Asset Retirement Obligations

The Company's asset retirement obligations (AROs) relate to future costs associated with plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The fair value of a liability for an ARO is recorded in the period in which it is incurred (typically when the asset is installed at the production location), and the cost of such liability increases the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period through charges to depreciation, depletion and amortization expense, and the capitalized cost is depleted on a units-of-production basis over the proved developed reserves of the related asset. Revisions to estimated AROs result in adjustments to the related capitalized asset and corresponding liability.

Deferred Financing Costs

Costs incurred in connection with the execution or modification of the Company’s credit facility, and in connection with the Company's senior and subordinated notes, are capitalized and amortized over the life, or expected life, of the debt using the effective interest method.

60

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

Prepaid Expenses and Other

The components of prepaid expenses and other are as follows:

	Year Ended December 31,	
(in thousands)	2011	2010
Prepaid expenses	5,275	9,590
Inventory	11,526	4,443
Total prepaid expenses and other	16,801	14,033

Accrued Liabilities

The components of accrued liabilities are as follows:

	Year Ended December 31,	
(in thousands)	2011	2010
Property taxes	$10,430	$11,245
Accrued interest	9,205	10,074
Accrued payroll	9,953	10,225
Other accrued liabilities	5,478	4,690
Total accrued liabilities	$35,066	$36,234

Revenue Recognition

Revenues associated with sales of oil, natural gas, electricity and natural gas marketing are recognized when delivery has occurred and title has transferred, and if the collectability of the revenue is probable. The electricity and natural gas the Company produces and uses in its operations are not included in revenues. Revenues from oil and natural gas production from properties in which the Company has an interest with other producers are recognized on the basis of its net working interest. Revenues are also derived from natural gas marketing sales, which represent excess capacity on the Rockies Express, Wyoming Interstate, and Ruby pipelines used by the Company to market natural gas for its working interest partners and other third parties.

Significant Customers

The Company sells oil and natural gas to various types of customers, including pipelines, refineries and other oil and natural gas companies, and electricity to utility companies. Credit is extended based on an evaluation of the customer's financial condition and historical payment record. The Company does not believe that the loss of any one customer would impact the marketability of its products, but it may impact the profitability of its oil, natural gas or electricity sold. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the Company's crude oil sales customer in Utah could impact the marketability of a portion of the Company's Utah crude oil volumes.

In 2011, sales to ExxonMobil Oil Corporation and Shell Trading (US) Company accounted for approximately 43% and 14%, respectively, of the Company's revenue. In 2010, sales to two purchasers were approximately 44% and 14%, respectively, of the Company's revenue. In 2009, sales to three purchasers were approximately 25%, 16% and 12%, respectively, of the Company's revenue.

61

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

Concentrations of Market Risk

The results of the Company's oil and natural gas operations are impacted by the market prices of oil and natural gas. The availability of a ready market for oil and natural gas products in the future depends on numerous factors beyond the Company's control, including weather, imports, proximity and capacity of oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of oil and natural gas products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

During 2011, 2010 and 2009, the Company did not incur any credit losses with respect to counterparties to contracts for the sale of oil and natural gas or under the Company's derivative instruments. As of December 31, 2011, over 87% of the Company's California oil production is under contract with Shell Trading (US) Company and ExxonMobil Oil Corporation. The Company's contract with Shell Trading (US) Company continues through June 30, 2013 and the Company's contract with ExxonMobil Oil Corporation renews automatically on a month-to-month basis, unless either party to the contract terminates upon 90 days' notice.

The Company places its temporary cash investments with high-quality financial institutions and does not limit the amount of credit exposure to any one financial institution. For the three years ended December 31, 2011, the Company has not incurred losses related to these investments.

Electricity Cost Allocation

The Company owns three cogeneration facilities. Its investment in cogeneration facilities has been for the express purpose of lowering steam costs in its heavy oil operations and securing operating control of the respective steam generation. Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine, which would otherwise be wasted, to produce steam. Such cogeneration operations also produce electricity. The Company allocates steam costs to its oil and natural gas operating costs based on the conversion efficiency of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to utility companies. A portion of the capital costs of the cogeneration facilities is allocated to DD&A—oil and natural gas production. Electricity production used in oil and natural gas operations is allocated to operating costs—oil and natural gas production, and totaled $2.3 million, $2.8 million and $2.8 million for the years ended December 31, 2011, 2010 and 2009 respectively.

Transportation Costs

Natural gas transportation costs are included in either operating costs—oil and natural gas production or operating costs—electricity generation, as applicable. Natural gas transportation costs included in operating costs—oil and natural gas production were $21.4 million, $16.2 million and $16.1 million for 2011, 2010 and 2009, respectively. Costs for transporting natural gas used in electricity generation were $5.0 million, $4.7 million and $2.8 million for 2011, 2010 and 2009, respectively; a portion of these costs are allocated to operating costs—oil and natural gas production, as described above, and the remainder are included in operating costs—electricity generation.

Stock-Based Compensation

The Company recognizes the grant date fair value of stock options and other stock based compensation issued in the Statements of Operations. Expense is recognized on a straight-line basis over the employee's requisite service period (generally the vesting period of the award).

62

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

(Loss) Earnings Per Share

The two-class method of computing earnings per share is required for entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Unvested restricted stock issued prior to January 1, 2010, under the Company's equity incentive plans, has the right to receive non-forfeitable dividends, participating on an equal basis with common stock, and thus these securities are classified as participating securities. Participating securities do not have a contractual obligation to share in the Company's losses. Therefore, in periods of net loss, no portion of the loss is allocated to participating securities. Unvested restricted stock issued subsequent to January 1, 2010, under the Company's equity incentive plans does not participate in dividends. Stock options issued under the Company's equity incentive plans do not participate in dividends.

Basic (loss) earnings per share is calculated by dividing (loss) earnings available to common shareholders by the weighted average shares-basic during each period. Under the treasury stock method, diluted (loss) earnings per share is calculated by dividing (loss) earnings available to common shareholders by the weighted average shares-dilutive, which includes the effect of potentially dilutive securities. Potentially dilutive securities consist of non-participating unvested restricted stock awards and outstanding stock options. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted (loss) earnings per share.

The following table shows the computation of basic and diluted net earnings per share from continuing and discontinued operations:

	Year Ended December 31,		
	2011	2010	2009
	(in thousands, except per share amounts)		
Net (loss) earnings from continuing operations	$(228,063)	$82,524	$47,224
Less: earnings allocable to participating securities	—	1,199	1,134
Net earnings from continuing operations available for common shareholders	$(228,063)	$81,325	$46,090
Net earnings from discontinued operations	$—	$—	$6,806
Less: earnings allocable to participating securities	—	—	174
Net earnings from discontinued operations available for common shareholders	$—	$—	$6,632
Basic (loss) earnings per share from continuing operations	$(4.21)	$1.54	$1.03
Basic earnings per share from discontinued operations	—	—	0.15
Basic (loss) earnings per share	$(4.21)	$1.54	$1.18
Dilutive (loss) earnings per share from continuing operations	$(4.21)	$1.52	$1.02
Dilutive earnings per share from discontinued operations	—	—	0.15
Dilutive (loss) earnings per share	$(4.21)	$1.52	$1.17
Basic weighted average shares	54,133	52,969	44,625
Add: dilutive effects of stock options	—	460	221

Diluted weighted average shares	54,133	53,429	44,846

Options of 1.5 million, 0.7 million and 1.6 million shares were not included in the weighted average shares-dilutive calculation for the years ended December 31, 2011, 2010 and 2009, respectively, because their effect would have been anti-dilutive.

63

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

Equity Method Investments

The Company owns interests in two entities that gather and transport natural gas in the Company's Lake Canyon and Brundage Canyon fields. The Company owns less than a 50% interest in both of these entities and such interests are accounted for using the equity method. The Company's net investment in these entities is included under the caption other assets on its Balance Sheets.

Comprehensive (Loss) Earnings

Comprehensive (loss) earnings is a term used to refer to net (loss) earnings plus other comprehensive earnings (loss). Other comprehensive (loss) earnings is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of shareholders' equity instead of net (loss) earnings. The components of other comprehensive (loss) earnings were as follows:

	Year Ended December 31,		
(in thousands)	2011	2010	2009
Net (loss) earnings	$(228,063)	$82,524	$54,030
Unrealized gain (loss) on derivatives, net of income taxes of $0, $0, and ($79,240), respectively	—	—	(129,287)
Reclassification of realized (gain) loss on derivatives included in net earnings, net of income taxes of $0, $0, ($27,447)	—	—	(44,782)
Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income taxes of $23,467, $10,153, and $0, respectively	38,289	16,566	—
Comprehensive (loss) earnings	$(189,774)	$99,090	$(120,039)

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development, and production of oil and natural gas, and all of the Company's operations are conducted in the continental United States. Consequently, the Company currently reports as a single industry segment.

Impact of Recently Issued Accounting Standard Updates

In December 2011, the FASB issued ASU No. 2011-11 Disclosures about Offsetting Assets and Liabilities. The ASU requires additional disclosures about the impact of offsetting, or netting, on a company's financial position, and is effective for annual periods beginning on or after January 1, 2013 and interim periods within those annual periods, and retrospectively for all comparative periods presented. Under US GAAP, derivative assets and liabilities can be offset under certain conditions. The ASU requires disclosures showing both gross information and net information about instruments eligible for offset in the balance sheet. The Company is currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on the Company's financial position or results of operations.

In June 2011, the FASB issued ASU No. 2011-05 Presentation of Comprehensive Income. The ASU amends previously issued authoritative guidance and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. These amendments remove the option under current U.S. GAAP to present the components of other comprehensive income as part of the statements of changes in stockholder's equity. In December

2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-12 Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards. The ASU supersedes pending paragraphs in ASU 2011-05 related to presenting reclassifications out of accumulated other comprehensive income by component in the financial statements. The adoption of this authoritative guidance will not have an impact on the Company's financial position or results of operations, but will require the Company to present the Statements of Comprehensive Income separately from its Statements of Shareholders' Equity, as these statements are currently presented on a combined basis.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

In May 2011, the FASB issued Accounting Standards Update (ASU) No. 2011-04 Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in US GAAP and IFRSs. The ASU amends previously issued authoritative guidance and requires new disclosures, clarifies existing disclosures and is effective for interim and annual periods beginning after December 15, 2011. The amendments change requirements for measuring fair value and disclosing information about those measurements. Additionally, the ASU clarifies the FASB's intent regarding the application of existing fair value measurement requirements and changes certain principles or requirements for measuring fair value or disclosing information about its measurements. For many of the requirements, the FASB does not intend the amendments to change the application of the existing Fair Value Measurements guidance. The Company is currently evaluating the provisions of ASU 2011-04 and assessing the impact, if any, it may have on the Company's financial position or results of operations.

2. Acquisitions and Divestitures

On May 25, 2011, the Company acquired interests in producing properties on approximately 6,000 net acres in the Wolfberry trend in the Permian for an aggregate purchase price of $128.4 million (the Wolfberry Acquisition). The Wolfberry Acquisition had an effective date of March 1, 2011, with operations from March 1, 2011 through May 24, 2011 resulting in purchase price adjustments. The acquisition was financed using the Company's senior secured revolving credit facility. The Company operates 98% of and has an average 93% working interest (70% net revenue interest) in the properties acquired in the Wolfberry Acquisition.

The Company has not presented pro forma information for the properties acquired in the Wolfberry Acquisition, as the impact of the acquisition was insignificant to the Company's Statements of Operations for the year ended December 31, 2011. Revenues of $7.8 million from properties acquired in the Wolfberry Acquisition have been included in the accompanying Statements of Operations for the year ended December 31, 2011, and earnings from the acquired properties were insignificant.

The following table summarizes the consideration paid to the sellers and the amounts of the assets acquired and liabilities assumed in the Wolfberry Acquisition:

	(in thousands)
Consideration paid to sellers:	
Cash consideration	$128,398
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed and undeveloped properties	128,697
Asset retirement obligation	(119)
Other liabilities assumed	(180)
Total identifiable net assets	$128,398

In March, April and November 2010, the Company completed three separate acquisitions of producing properties located in the Wolfberry trend in the Permian for an aggregate purchase price of approximately $327.0 million (the Permian Acquisitions). The Permian Acquisitions were financed with net proceeds from the issuance in January 2010 of 8 million shares of the Company's Class A Common Stock, cash generated from operations and net proceeds from the issuance in November 2010 of $300 million aggregate principal amount of the Company's 6.75% senior notes due 2020 (2020 Notes).

In the first quarter of 2011, the Company recorded a $1.0 million gain (net of deferred income taxes of $0.7 million) in conjunction with usual and customary post-closing adjustments to the purchase price of the November 2010 Permian acquisition. The gain was recorded in the Statements of Operations under the caption gain on purchase.

Acquisition costs of $2.6 million were recorded for the Permian Acquisitions in the Statements of Operations under the caption transaction costs on acquisitions for the year ended December 31, 2010. Revenues of $28.7 million were included in the accompanying Statements of Operations for the year ended December 31, 2010, and earnings from the acquired properties in 2010 were insignificant.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
2. Acquisitions and Divestiture (Continued)

The following table summarizes the consideration paid to the sellers and the amounts of the assets acquired and liabilities assumed in the Permian Acquisitions:

	(in thousands)
Consideration paid to sellers:	
Cash consideration	$327,032
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed and undeveloped properties	332,214
Other assets acquired	342
Asset retirement obligation	(3,498)
Deferred income tax liability	(647)
Other liabilities assumed	(333)
Total identifiable net assets	$328,078

The Wolfberry Acquisition and the Permian Acquisitions qualify as business combinations and, as such, the Company estimated the fair value of each property as of each acquisition date (the date on which the Company obtained control of the properties). The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model based on an income approach and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. Given the unobservable nature of the inputs, nonrecurring measurements of business combinations are deemed to use Level 3 inputs.

In March 2009, the Company entered into an agreement to sell its assets in the Denver-Julesburg basin in Colorado. The transaction closed in April 2009. The Company recorded a pre-tax impairment loss of $9.6 million related to the sale, which is included in net earnings from discontinued operations in its Statements of Operations for the year ended December 31, 2009.

Earnings from discontinued operations, net of income tax, on the accompanying Statements of Operations for the year ended December 31, 2009 is comprised of the following (in thousands):

	Year Ended December 31, 2009
Sales of oil and natural gas(1)	$11,555
Loss on sale of asset	(908)
Other revenue	623
Total revenues	11,270
Realized and unrealized (gain) on derivatives, net	(13,786)
Other expenses(2)	15,799
Total expenses	2,013
Earnings from discontinued operations, before income taxes	9,257
Provision for income taxes	2,451
Net earnings from discontinued operations	$6,806

(1)

A $6.2 million realized gain included in sales of oil and natural gas was reclassified to discontinued operations for the year ended December 31, 2009.

(2) Includes $9.6 million of impairment charges related to the sale of the Company's assets in the DJ and $0.8 million of interest allocated to discontinued operations based on the ratio of net assets to the sum of total net assets.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
2. Acquisitions and Divestiture (Continued)

At the time of the DJ asset sale, the Company had designated derivative instruments as cash flow hedges from the forecasted sale of natural gas produced by the DJ assets. As such, all recurring impacts on the Company's Statements of Operations were classified as discontinued operations. Additionally, the Company determined that as a result of the sale of the DJ assets, the forecasted transactions were no longer probable of occurring. Accordingly, the Company discontinued hedge accounting for such derivative instruments and reclassified a gain of $14.3 million from AOCL to net earnings from discontinued operations in its Statements of Operations.

During the first quarter of 2009, the Company entered into natural gas derivative instruments on behalf of the purchaser of its DJ assets. The Company did not elect hedge accounting for these derivative instruments and recorded an unrealized net loss of $0.5 million which is included in net earnings from discontinue operations in its Company's Statements of Operations.

3. Assets Held For Sale

At December 31, 2011, the Company's assets held for sale had a balance of $14.6 million related to proved developed properties in Elko, Eureka, and Nye Counties, Nevada (Nevada Assets). On December 21, 2011, the Company entered into an agreement to sell its Nevada Assets to a group of private buyers for $16.5 million, subject to customary closing adjustments. The sale of the Nevada Assets was effective January 1, 2012 and closed January 31, 2012. The Company received a deposit of $3.3 million on December 22, 2011 for the sale of these assets, which is recorded under accrued liabilities on the Balance Sheets at December 31, 2011.The asset retirement obligation related to the Nevada Assets was $0.7 million at December 31, 2011 and is included in the asset retirement obligations liability on the December 31, 2011 Balance Sheets.

4. Debt

Revolving Credit Facility

The Company's senior secured revolving credit facility, which matures on May 13, 2016, has a current borrowing base of $1.4 billion, subject to lender commitments. On October 26, 2011, as part of the semi-annual borrowing base redetermination process, the Company entered into an amendment to the credit facility which, among other things, increased total lender commitments to $1.2 billion. Borrowings under the credit facility bear interest at either (i) LIBOR plus a margin between 1.50% and 2.50% or (ii) the prime rate plus a margin between 0.50% and 1.50%, in each case, based on the amount utilized. The annual commitment fee on the unused portion of the credit facility ranges between 0.35% and 0.50% based on the amount utilized. Total fees paid during 2011 to increase the borrowing base and lender commitments were approximately $2.2 million, and will be amortized over the remaining term of the credit facility. The Company wrote off debt issuance costs of $0.5 million during the fourth quarter associated with one lender that did not renew its commitment to the credit facility.

As of December 31, 2011, outstanding borrowings under the facility were $531.5 million (excluding $23.2 million of outstanding letters of credit), leaving $645.3 million in borrowing capacity available under the credit facility. As of December 31, 2010, there were $170.0 million in outstanding borrowings under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of the Company's proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. The Company and the lenders each have a right to one additional redetermination each year.

The credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. The senior secured revolving credit facility contains other customary covenants, subject to certain agreed exceptions, including covenants restricting the Company's ability to, among other things, owe or be liable for indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of the Company's material assets or properties; declare dividends on or redeem or repurchase the Company's capital stock; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; engage in transactions with affiliates; and enter into, create or allow to exist contractual obligations limiting the Company's ability to grant liens on the Company's assets to the lenders under the senior secured revolving credit facility. The Company are currently in compliance with all financial covenants and have complied with all financial covenants for all prior periods presented

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
4. Debt (Continued)

Subject to certain agreed limitations, the Company granted first priority security interests over substantially all of its assets in favor of the lenders under the credit facility.

Money Market Line of Credit

The Company's senior secured uncommitted money market line of credit has a borrowing capacity of up to $40 million for a maximum of 30 days. As of December 31, 2011, there were no borrowings outstanding under the money market line of credit. Amounts borrowed under the money market line of credit bear interest at LIBOR plus a margin of approximately 1.4%. The line of credit is currently unavailable to the Company and the Company does not know when or if the line of credit will be available in the future. As of December 31, 2010 there was $5.3 million in outstanding borrowings under the line of credit. The outstanding borrowings under the line of credit at December 31, 2010 had a weighted average interest rate of 1.7%.

6.75% Senior Notes Due 2020

On November 1, 2010, the Company issued $300 million in principal amount of 2020 Notes. Interest is payable in arrears semi-annually in May and November of each year, beginning May 2011. The Company received net proceeds of $294.0 million, which were used in part to finance a November 2010 acquisition of producing properties in the Permian and the remainder was used to reduce outstanding borrowings under the credit facility. The 2020 Notes are senior unsecured obligations of the Company and rank effectively junior to all of the Company's existing and any future secured debt, to the extent of the value of the collateral securing that debt, rank equally in right of payment with the 2014 Notes and any future senior unsecured debt, and rank senior in right of payment to the Company's 8.25% senior subordinated notes due 2016 (2016 Notes) and the Company's other future subordinated debt.

The Company may redeem up to 35% of the 2020 Notes at any time prior to November 1, 2013, on one or more occasions, with the proceeds of certain equity offerings at a redemption price of 106.75%. The Company may redeem all or any part of the 2020 Notes at any time beginning on or after November 1, 2015 at the prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued and unpaid interest:

2015	103.375	%
2016	102.250	%
2017	101.125	%
2018 and thereafter	100.000	%

The Company may also redeem the 2020 Notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium, plus accrued and unpaid interest to the redemption date.

10.25% Senior Notes Due 2014

On May 27, 2009, the Company issued $325 million in principal amount of its 10.25% senior notes due 2014 (2014 Notes) at 93.546% of par resulting in a discount of $21.0 million. Interest is payable in arrears semi-annually on June 1 and December 1 of each year. The Company received net proceeds of $295.1 million, which were used to repay the $140 million second lien term loan in full and reduce outstanding borrowings under the credit facility.

On August 13, 2009, the Company issued an additional $125 million principal amount of 2014 Notes at 104.75% of par resulting in a premium of $6 million. Interest is payable in arrears semi-annually on June 1 and December 1 of each year. The Company received net proceeds of $129.1 million, which were used to reduce outstanding borrowings under the credit facility.

The 2014 Notes are treated as a single series of debt securities and are carried on the balance sheet at their combined amortized cost. The 2014 Notes are senior unsecured obligations of the Company, which rank effectively junior to all of the Company's existing and any future secured debt, to the extent of the value of the collateral securing that debt, rank equally in right of payment with the 2020 Notes and any future senior unsecured debt, and rank senior in right of payment to the 2016 Notes and the Company's other future subordinated debt.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
4. Debt (Continued)

The 2014 Notes are redeemable at the Company's option, in whole or in part, at any time at a price equal to 100% of the principal amount of the 2014 Notes plus accrued and unpaid interest, if any, plus a "make-whole" premium.

From August to October 2011, the Company repurchased $94.7 million aggregate principal amount of its 2014 Notes for an aggregate purchase price of $108.8 million, including accrued and unpaid interest. The related loss of $15.0 million recorded in extinguishment of debt consists of $11.5 million in premium paid over par and $3.5 million in write-offs of net discount and deferred financing costs. These notes were repurchased using available borrowings under the credit facility. The Company may from time to time seek to repurchase its outstanding debt, including additional 10.25% Notes, through open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions and other factors. The amounts repurchased may be material.

8.25% Senior Subordinated Notes Due 2016

In 2006, the Company issued $200 million of 2016 Notes at par for proceeds of $196.0 million. Interest on the 2016 Notes is paid semiannually in May 1 and November 1 of each year. The 2016 Notes rank junior to all of the Company's existing and any future secured debt, to the extent of the value of the collateral securing that debt, junior in right of payment to the 2014 and 2020 Notes and any future senior unsecured debt, and equally in right of payment with any future senior subordinated indebtedness.

The Company may redeem the 2016 Notes at any time beginning on or after November 1, 2011 at the prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued but unpaid interest:

2011	104.125	%
2012	102.750	%
2013	101.375	%
2014 and thereafter	100.000	%

The Company may also redeem the 2016 Sub Notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus accrued and unpaid interest plus a "make-whole" premium.

5. Income Taxes

The (benefit) provision for income taxes from continuing operations consists of the following (in thousands):

	Year Ended December 31,				
	2011		2010	2009	
Current:					
Federal	$4,115		$363	$3,148	
State	2,936		1,870	782	
	7,051		2,233	3,930	
Deferred:					
Federal	(125,261	)	47,709	20,885	
State	(24,018	)	4,026	(4,151	)
	(149,279	)	51,735	16,734	
Total	$(142,228	)	$53,968	$20,664	

69

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
5. Income Taxes (Continued)

The components of the net deferred income tax liabilities consist of the following:

(in thousands)	Year Ended December 31, 2011	2010
Deferred income tax assets:		
Federal benefit of state income taxes	$(2,479)	$6,862
Credit carryforwards	28,783	28,808
Equity and deferred compensation	12,620	11,229
Derivatives	8,669	26,838
Net operating loss	412	14,545
Other, net	29	1,293
	48,034	89,575
Deferred income tax liabilities:		
Depreciation and depletion	(219,705)	(386,440)
	(219,705)	(386,440)
Net deferred income tax liabilities	$(171,671)	$(296,865)

At December 31, 2011, the Company's net deferred income tax assets and liabilities were recorded as a current asset of $13.8 million and a long-term liability of $185.5 million. At December 31, 2010, the Company's net deferred income tax assets and liabilities were recorded as a current asset of $32.3 million and a long-term liability of $329.2 million.

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

	Year Ended December 31, 2011	2010	2009
Income tax computed at statutory federal rate	35 %	35 %	35 %
State income taxes, net of federal benefit	3	4	4
Deferred state rate impact	—	(1)	(5)
Net impact to uncertain income tax positions	1	—	(2)
Other	(1)	2	(2)
Effective income tax rate	38 %	40 %	30 %

As of December 31, 2011, the Company had approximately $11.1 million of federal and $13.5 million of state (California) EOR tax credit carryforwards available to reduce future income taxes. The EOR credits will begin to expire, if unused, in 2025 and 2016 for federal and California purposes, respectively. The Company has federal alternative minimum income tax (AMT) credit carryforwards of $0.8 million and California AMT credits of $0.7 million that do not expire and can be used to offset regular income taxes in future years to the extent that regular income taxes exceed the AMT in any such year. The Company also has Colorado enterprise zone income tax credits of $2.5 million that will begin to expire in 2018 if not used.

In 2011, the Company executed a final audit settlement that reduced unrecognized income tax benefits by $2.3 million, which resulted in a reduction of the effective income tax rate. As of December 31, 2011, the Company had a gross liability for uncertain income tax benefits of $2.9 million which, if recognized, would affect the effective income tax rate. The Company estimates that it is reasonably possible that the balance of unrecognized income tax benefits as of December 31, 2011 could decrease by a maximum of $2.7 million in the next 12 months due to the expiration of statutes of limitations. The Company recognizes potential accrued interest and penalties related to unrecognized income tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. The Company had accrued approximately $0.8 million of interest related to its uncertain income tax positions as of December 31, 2011 and 2010.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
5. Income Taxes (Continued)

The Company recognized a net benefit of $2.3 million, $0.0 million and $3.6 million due to the closure of certain federal and state income tax years, offset by additional uncertain income tax position accruals net of interest expense of $0.5 million, $0.1 million and $0.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

The following table illustrates changes in the gross unrecognized income tax benefits:

(in millions)	Year Ended December 31,		
	2011	2010	2009
Unrecognized income tax benefits at January 1	$5.2	$6.1	$12.0
Decreases for positions taken in current year	—	—	(0.1)
Decreases for positions taken in a prior year	—	(0.8)	(1.3)
Decreases for settlements with taxing authorities	(2.3)	—	(3.6)
Decreases for lapses in the applicable statute of limitations	—	(0.1)	(0.9)
Unrecognized income tax benefits at December 31	$2.9	$5.2	$6.1

As of December 31, 2011, the Company remains subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction:	Tax Years Subject to Exam:
Federal	2007 - 2010
California	2007 - 2010
Colorado	2007 - 2010
Texas	2007 - 2010
Utah	2008 - 2010

6. Shareholders' Equity

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital Stock," are 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.

Common Stock Offering

In January 2010, the Company issued 8.0 million shares of Class A Common Stock at a price of $29.25 per share. Net proceeds from this offering were $224.3 million. The Company used the net proceeds from the offering to fund a March 2010 acquisition in the Permian and to repay a portion of the outstanding borrowings under the credit facility. See Note 2 to the Financial Statements.

Dividends

The regular annual dividend for 2011 was $0.31 per share. On August 23, 2011, the Company’s Board of Directors approved an increase in the Company’s quarterly dividend of one-half cent per share from $0.075 to $0.08 per share, beginning with the September 2011 dividend. The Company's dividend is payable quarterly in March, June, September and December. Dividend payments are limited by covenants in the (i) credit facility to the greater of $35 million or 75% of net earnings for any four quarter period, and (ii) indentures governing the Company's senior and subordinated indentures to up to $0.36 per share annually (but in no event in excess of $20 million annually) in the event that the Company is not in default, and up to $10 million in the event that the Company is in a non-payment default.

Table of Contents

7. Equity Incentive Compensation Plans and Other Benefit Plans

The Company's 2010 Equity Incentive Plan (the 2010 Plan), approved by the Company's shareholders in May 2010, provides for granting of equity compensation up to an aggregate of 1,000,000 shares of Common Stock. The purpose of the 2010 Plan is to encourage ownership in the Company by key personnel whose long-term service is considered essential to the Company's continued progress and, thereby, align participants' and shareholders' interests. Stock options, stock appreciation rights (SARs), cash awards and stock awards, including restricted shares and stock units, may be granted under the 2010 Plan. The exercise price of an option may not be less than the fair market value of one share of Common Stock on the date of grant. Stock options and restricted stock awards granted under the 2010 Plan have historically vested either in increments of 25% on each of the first four anniversary dates of the date of grant or 100% after three years. Stock options and restricted stock units (RSUs) granted to non-employee directors have historically vested immediately. Options granted under the 2010 Plan have a term of 10 years. As of December 31, 2011, the Company had 697,596 shares available to be issued under the 2010 Plan.

The 2005 Equity Incentive Plan (the 2005 Plan), approved by the Company's shareholders in May 2005, provides for granting of equity compensation up to an aggregate of 2,900,000 shares of Common Stock. The purpose of the 2005 Plan is to encourage ownership in the Company by key personnel whose long-term service is considered essential to the Company's continued progress and, thereby, align participants' and shareholders' interests. Stock options, stock appreciation rights (SARs), cash awards and stock awards, including restricted shares and stock units, may be granted under the 2005 Plan. The exercise price of an option shall not be less than the fair market value of one share of Common Stock on the date of grant. Stock options and restricted stock awards granted under the 2005 Plan have historically vested in increments of 25% on each of the first four anniversary dates of the date of grant or 100% after three years. Stock options and RSUs granted to non-employee directors have historically vested immediately. Options granted under the 2005 Plan have a term of 10 years. As of December 31, 2011, the Company had 189,297 shares available to be issued under the 2005 Plan.

Total compensation expense recognized in the Statements of Operations for grants under the Company's equity incentive plans was $9.0 million, $8.3 million and $7.7 million in 2011, 2010 and 2009, respectively.

Stock Options

The following table summarizes stock option activity for the years ended December 31, 2011, 2010 and 2009:

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)(1)	Number of Shares Exercisable
Outstanding at January 1, 2009	2,421,650	$25.16	$—	1,842,532
Granted	—	—		
Exercised	(62,050)	13.52	560	
Cancelled/expired	(83,580)	28.48		
Outstanding as of December 31, 2009	2,276,020	25.36	15,296	2,008,325
Granted	—	—		
Exercised	(227,100)	19.40	3,570	

Cancelled/expired	(31,695)	35.51		
Outstanding at December 31, 2010	2,017,225	25.87	35,974	1,884,937
Granted	89,865	48.50		
Exercised	(579,635)	17.47	17,746	
Cancelled/expired	(6,765)	45.92		
Outstanding at December 31, 2011	1,520,690	$30.32	$17,798	1,434,020

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock at the end of the related period exceeds the exercise price of the option.

In March 2011, 89,865 stock options were granted under the 2010 Plan to certain executive officers and other officers of the Company with exercise prices equal to the closing market price of the Company's Common Stock on the grant date. These stock options generally vest ratably over a four-year service period from the grant date and are exercisable immediately upon vesting through the tenth anniversary of the grant date.

The fair value of each option granted was estimated using the Black-Scholes option pricing model. Expected volatility was calculated based on the historical volatility of the Company's Common Stock, and the risk-free interest rate was based on U.S. treasury yield curve rates with maturities consistent with the expected life of each stock option. The key assumptions used in computing the weighted average fair market value of stock options granted were as follows:

	2011	
Expected volatility	45.00	%
Risk-free rate	2.54	%
Dividend yield	0.62	%
Expected term (in years)	6.0	

The following table summarizes information about stock options outstanding at December 31, 2011:

	Stock Options Outstanding				Stock Options Exercisable			
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighed Average Exercise Price	Aggregate Intrinsic Value (in thousands)	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighed Average Exercise Price	Aggregate Intrinsic Value (in thousands)
\$7.00-\$15.00	199,000	2.13	\$ 12.36	5,902	199,000	2.13	\$ 12.36	\$ 5,902
\$15.01-\$25.00	287,000	2.90	21.60	5,861	287,000	2.90	21.60	5,861
\$25.01-\$35.00	655,001	4.51	31.65	6,792	655,001	4.51	31.65	6,792
\$35.01-\$48.50	379,689	6.79	44.01	—	293,019	6.09	42.68	—
	1,520,690	4.47	\$ 30.32	17,798	1,434,020	4.18	\$ 29.22	\$ 18,360

As of December 31, 2011, there was \$1.3 million of total unrecognized compensation expense related to outstanding stock options, which is expected to be recognized over the next 3.25 years.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
7. Equity Incentive Compensation Plans and Other Benefit Plans (Continued)

Restricted Stock Units
The following table summarizes RSU activity for the years ended December 31, 2011, 2010 and 2009:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Vest Date Fair Value (in thousands)
Outstanding at January 1, 2009	966,198	$20.83	
Granted	294,504	26.72	
Issued	(107,375)	28.98	$2,574
Canceled/expired	(46,034)	25.08	
Outstanding at December 31, 2009(1)(2)	1,107,293	$22.14	
Granted	34,529	30.94	
Issued	(246,633)	28.98	$7,813
Canceled/expired	(37,829)	22.20	
Outstanding at December 31, 2010(1)(2)	857,360	$19.67	
Granted	159,333	47.98	
Issued	(62,127)	26.18	$2,588
Canceled/expired	(39,544)	25.12	
Outstanding at December 31, 2011(1)(2)	915,022	$23.88	

(1) The balance outstanding includes RSUs granted to the non-employee directors that 100% vested at date of grant but are subject to a deferral election before the corresponding shares of Common Stock are issued. For the years ended December 31, 2011, 2010 and 2009, 30,544, 10,522 and 10,522 RSUs have vested, but the corresponding shares of Common Stock have not been issued.

(2) The balance outstanding includes RSUs granted to executive officers and other officers that have vested in accordance with the RSU agreement, but are subject to a deferral election before the corresponding shares of Common Stock are issued. For the years ended December 31, 2011, 2010 and 2009, 483,908, 289,335, and 124,799 RSUs have vested, but the corresponding shares of Common Stock have not been issued.

The grant date fair value of RSUs issued under the 2005 Plan was determined by reference to the average high and low stock price of a share of Common Stock on the date of grant. The grant date fair value of RSUs issued under the 2010 Plan was determined by reference to the closing price of a share of Common Stock on the date of grant. The Company uses historical data and projections to estimate expected restricted stock forfeitures. The expected forfeitures are then included as part of the grant date estimate of compensation cost.

As of December 31, 2011, there was $7.9 million of total unrecognized compensation expense related to RSUs granted. That cost is expected to be recognized over 3.25 years.

74

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
7. Equity Incentive Compensation Plans and Other Benefit Plans (Continued)

Performance Share Program

The following table summarizes performance share award activity for the years ended December 31, 2011, 2010 and 2009:

	Performance Share Awards	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at January 1, 2009	—	$—	
Granted	—	—	
Issued	—	—	$—
Canceled/expired	—	—	
Outstanding at December 31, 2009	—	$—	
Granted	103,794	31.20	
Issued	—	—	$—
Canceled/expired	—	—	
Outstanding at December 31, 2010	103,794	$31.20	
Granted	65,620	51.86	
Issued	—	—	$—
Canceled/expired	(6,565)	44.20	
Outstanding at December 31, 2011	162,849	$39.00	

In March 2011, 65,620 RSUs that are subject to internal performance metrics and market based vesting criteria in addition to a three-year service condition (performance share awards), were granted to executive officers and other officers. The ultimate vesting of performance share awards is contingent upon meeting the established criteria. From January 1, 2011 to December 31, 2013, the Company must maintain an interest coverage ratio of at least 2.5 to 1.0. The number of performance share awards that ultimately vest is based on two equally weighted performance factors: (i) average daily production growth with respect to certain of the Company's assets on an annual basis and (ii) total shareholder return as compared to the Company's defined peer group for years 2011-2013.

For the portion of the performance share awards subject to internal performance metrics, the grant date fair value was determined by reference to the closing price of a share of Common Stock on the date of grant. The Company recognizes compensation expense when it becomes probable that these conditions will be achieved. However, any such compensation expense recognized is reversed if vesting does not actually occur.

For the portion of the performance share awards subject to market based vesting criteria, the grant date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company's Common Stock, and the risk-free interest rate is based on U.S. treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing the market-based portion of the performance share awards were as follows:

	2011	2010
Number of simulations	100,000	100,000
Expected volatility	44%	79%
Risk-free rate	1.15%	1.36%

The total grant date fair value of the market-based portion of the performance share awards issued in 2011 and 2010, as determined by the Monte Carlo valuation model, was $1.1 million and $1.0 million, respectively, and is being recognized ratably over the respective three-year vesting period. Compensation expense for the market-based portion of the performance share awards is not reversed if vesting does not actually occur.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
7. Equity Incentive Compensation Plans and Other Benefit Plans (Continued)

As of December 31, 2011, there was $1.4 million of total unrecognized compensation cost related to performance share awards granted. This cost is expected to be recognized over 2 years.

Director Fees

The Company's directors may elect to receive their annual retainer and meeting fees in the form of the Company's Common Stock issued pursuant to the Company's Non-Employee Director Deferred Stock and Compensation Plan (the Deferred Plan). The plan permits eligible directors, in recognition of their contributions to the Company, 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 is made in shares of Common Stock. The distribution from the interest account is made in cash. Shares of Common Stock earned and deferred in accordance with the Deferred Plan as of December 31, 2011, 2010 and 2009 were 13,647, 38,462, and 124,686, respectively.

Amounts allocated to the stock unit account have the right to receive a "dividend equivalent" equal to the dividends declared and paid by the Company. The dividend equivalent is treated as reinvested in an additional number of units and credited to the director's account using an established market value. Amounts allocated to the interest account are credited with interest at an established interest rate.

Other Employee Benefits—401(k) Plan

The Company sponsors 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. The Company currently matches 100% of each employee's contribution up to 8% of an employee's eligible compensation. The Company's contributions to the 401(k) Plan, net of forfeitures, for the years ended December 31, 2011, 2010 and 2009 were $1.8 million, $1.5 million and $1.4 million, respectively. Employees are eligible to participate in the 401(k) Plan on their date of hire and approximately 98% of the Company's employees participated in the 401(k) Plan in 2011.

8. Derivative Instruments

The Company uses financial derivative instruments as part of its price risk management program to achieve a more predictable, economic cash flow from its oil and natural gas production by reducing its exposure to price fluctuations. The Company has entered into financial commodity swap and collar contracts to fix the floor and ceiling prices received for a portion of the Company's oil and natural gas production. The terms of the contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and future financial commitments. The Company periodically enters into interest rate derivative contracts to protect against changes in interest rates on its floating rate debt. For further discussion related to the fair value of the Company's derivatives see Note 9 to the Financial Statements.

As of December 31, 2011, the Company had commodity derivatives associated with the following volumes:

	2012	2013	2014
Oil Bbl/D:	21,000	15,000	2,000
Natural Gas MMBtu/D:	15,000	—	—

Based on NYMEX strip pricing as of December 31, 2011, the Company would receive payments under existing derivative contracts of $5.3 million during the next twelve months.

Discontinuance of Hedge Accounting

Effective January 1, 2010, the Company elected to de-designate all of its commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009. As a result, subsequent to December 31, 2009, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCL. As a result of discontinuing hedge accounting on January 1, 2010, the fair values of the Company's open derivative instruments designated as cash flow hedges as of December 31, 2009, less any ineffectiveness recognized, were frozen in AOCL and are reclassified into earnings as the original hedge transactions settle.

At December 31, 2011, AOCL consisted of $8.9 million ($5.5 million net of income tax) of unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. At December 31, 2010, AOCL consisted of $70.7 million ($43.8 million net of income tax) of unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. During the years ended December 31, 2011 and December 31, 2010, $61.8 million ($38.3 million, net of income tax) and $26.7 million ($16.6 million, net of income tax), respectively, of non-cash amortization of AOCL related to discontinuing hedge accounting was reclassified from AOCL into earnings. The Company expects to reclassify into earnings from AOCL pre-tax net losses of $8.9 million related to de-designated commodity and interest rate derivative contracts during the next 12 months.

In the fourth quarter of 2010, the Company terminated interest rate derivative instruments that were previously designated as cash flow hedges. The termination resulted in a cash settlement of $10.8 million, offset by a fair value gain of $8.9 million. The net loss of $1.9 million is included in realized and unrealized (gain) loss on derivatives, net.

The following tables detail the fair value of derivatives recorded on the Company's Balance Sheets, by category:

	December 31, 2011			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	$6.1	Derivative liabilities	$20.4
Long-term:				
Commodity	Derivative assets	7.0	Derivative liabilities	15.5
Total derivatives		$13.1		$35.9

	December 31, 2010			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	$2.7	Derivative liabilities	$84.9
Long-term:				
Commodity	Derivative assets	2.1	Derivative liabilities	33.5
Total derivatives		$4.8		$118.4

The tables below summarize the location and the amount of derivative instrument (gains) losses before income taxes reported in the Statements of Operations for the periods indicated:

(in millions)		Year Ended December 31,		
Derivatives cash flow hedging relationships	Location of (Gain) Loss Recognized in Earnings	2011	2010	2009
Commodity				
Loss recognized in AOCL (effective portion)	Accumulated other comprehensive loss	—	—	206.4
(Gain) reclassified from AOCL into earnings (effective portion)	Sales of oil and natural gas	—	—	(58.8)
(Gain) reclassified from AOCL into earnings (effective portion)	Earnings from discontinued operations	—	—	(20.5)
Loss recognized in earnings (ineffective portion)	Realized and unrealized (gain) loss on derivatives, net	—	—	0.6
Loss reclassified from AOCL into earnings (amortization of frozen amounts)	Sales of oil and natural gas	60.9	18.4	—
Interest rate				
Loss recognized in AOCL (effective portion)	Accumulated other comprehensive loss	—	—	2.7
Loss reclassified from AOCL into earnings (effective portion)	Interest	—	—	7.0
Loss reclassified from AOCL into earnings (amortization of frozen amounts)	Interest	0.8	8.3	—

(in millions)		Year Ended December 31,		
Derivatives not designated as hedging instruments under authoritative guidance	Location of (Gain) Loss Recognized in Earnings	2011	2010	2009
Commodity				
(Gain) loss recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized (gain) loss on derivatives, net	(13.9)	23.2	7.2
(Gain) loss recognized in earnings (cash settlements and mark-to-market movements)	Earnings from discontinued operations	—	—	0.5
Interest rate				
(Gain) loss reclassified from AOCL into earnings (amortization of frozen amounts)	Realized and unrealized (gain) loss on derivatives, net	—	8.6	—

Credit Risk

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the contracts with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions, the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that the Company would have incurred if all counterparties to its derivative contracts failed to perform at December 31, 2011 was $7.5 million.

As of December 31, 2011, the counterparties to the Company's commodity derivative contracts consist of seven financial institutions. The Company's counterparties or their affiliates are generally lenders, or affiliates of lenders, under the Company's credit facility. As a result, the counterparties to the Company's derivative contracts share in the collateral supporting the Company's credit facility. The Company is not generally required to post additional collateral under derivative contracts.

Certain of the Company's derivative contracts contain cross default provisions that accelerate of amounts due under such contract if the Company defaults on its obligations under its material debt agreements. In addition, if the Company defaults on certain of its material debt agreements, including, potentially, its derivative contracts, the Company would be in default under the credit facility. As of December 31, 2011, the Company was in a net liability position with four of its counterparties, the fair value of which was $30.2 million. As of December 31, 2011, the Company's largest two counterparties accounted for 84% of the value of its total derivative positions.

9. Fair Value Measurement

The authoritative guidance for fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

A financial instrument's categorization within the fair value hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. The fair value of all derivative instruments is estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The fair value of all derivative instruments is estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services, and the Company has made no adjustments to the obtained prices. The independent pricing services publish observable market information from multiple brokers and exchanges. All valuations were compared against counterparty valuations to verify the reasonableness of prices. The Company also considers counterparty credit risk and its own credit risk in its determination of all estimated fair values. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative contracts it holds. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

Liabilities Measured at Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy the Company's net derivative liabilities that were measured at fair value on a recurring basis as of December 31, 2011 and 2010:

(in millions)	Total	Level 1	Level 2	Level 3
Commodity derivatives liability, net				
December 31, 2011	$22.7	$—	$22.7	$—
December 31, 2010	$113.6	$—	$11.8	$101.8

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
9. Fair Value Measurement (Continued)

Changes in Level 3 Fair Value Measurements

The table below includes a rollforward of amounts included in the Company's Balance Sheet (including the change in fair value) for financial instruments classified by the Company within Level 3 of the fair value hierarchy. When a determination is made to classify a financial instrument within Level 3 of the fair value 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).

	Year Ended December 31,		
(in millions)	2011	2010	2009
Fair value liability (asset), beginning of period	$101.8	$26.0	$(172.5)
Transfer out of Level 3(1)	(101.8)	—	(3.4)
Realized and unrealized (gain) loss included in earnings	—	37.4	(71.0)
Unrealized loss included in accumulated other comprehensive loss	—	—	201.9
Settlements	—	38.4	71.0
Fair value liability, end of period	$—	$101.8	$26.0
Total unrealized (gain) loss included in earnings related to financial assets and liabilities still on the Balance Sheets	$—	$75.8	$(0.4)

(1) During the first quarter of 2011, the inputs used to value oil collars, natural gas collars and natural gas basis swaps were directly or indirectly observable, and these instruments were transferred to level 2.

The $3.4 million of transfers out of Level 3 for the year ended December 31, 2009 represent crude oil collars that were converted to crude oil swaps during the first quarter of 2009.

For further discussion related to the Company's derivatives, see Note 8 to the Financial Statements.

Fair Market Value of Financial Instruments

The Company uses various assumptions and methods in estimating the fair values of its financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short-term maturity of these instruments. The carrying amount of the Company's credit facility and line of credit approximated fair value because the interest rates are variable and could be at similar rates today. The fair values of the 2016 Notes, the 2014 Notes, and the 2020 Notes were estimated based on quoted market prices. The fair values of the Company's derivative instruments are discussed above.

	December 31, 2011		December 31, 2010	
(in millions)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Line of credit	$—	$—	$5	$5
Senior secured revolving credit facility	532	532	170	170
8.25% Senior subordinated notes due 2016	200	209	200	210
10.25% Senior notes due 2014, net of unamortized discount of $6,564 and $11,035, respectively	349	402	439	518

6.75% Senior notes due 2020	300	302	300	303
	$1,381	$1,445	$1,114	$1,206

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
9. Fair Value Measurement (Continued)

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The Company applies the provisions of the fair value measurement standard to its non-recurring, non-financial measurements including business combinations, oil and natural gas property impairments and other long-lived asset impairments. These items are not measured at fair value on a recurring basis but are subject to fair value adjustments only in certain circumstances.

In 2011, the Company recognized impairment losses of $625.0 million and $4.3 million related to natural gas properties and other long-lived assets (drilling rigs), respectively. In 2009, the Company recognized an impairment loss of $4.2 million related to other long-lived assets. The following tables present information about the Company's non-financial assets measured at fair value on a non-recurring basis as of December 31, 2011 and 2009 and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values:

		Fair Value Measurements (in millions) Using			
Description	Carrying Value at 12/31/2011	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Losses Recognized in 2011
Natural Gas Properties	$114.3	—	—	114.3	$625.0
Other Long-Lived Assets	1.4	—	—	1.4	4.3
					$629.3

		Fair Value Measurements (in millions) Using			
Description	Carrying Value at 12/31/2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Losses Recognized in 2009
Other Long-Lived Assets	$3.3	—	—	3.3	$4.2

See Notes 2 and 11 to the Financial Statements for additional information on the methods and assumptions used to estimate the fair values of the Company's assets measured at fair value on a nonrecurring basis.

10. Commitments and Contingencies

Operating Leases and Other Commitments

The Company leases corporate and field offices in California, Colorado and Texas under agreements expiring over the next five years. In 2006, the Company purchased an airplane for business travel which was subsequently sold and contracted under a ten year operating lease beginning December 2006. The Company also finances vehicles under operating leases, which expire over the next three years. Rent expense with respect to these lease commitments was $2.6 million for each of the years ended December 31, 2011, 2010 and 2009. The Company currently has four drilling rigs under contracts that require minimum payments for the full contract term or penalties upon early termination. All of these contracts expire during 2012. All other rigs currently performing work for the Company are on a well-by-well basis and can be released without penalty at the conclusion of drilling on the current well. The Company also has other commitments relating primarily to natural gas purchases, cogeneration facility management services and equipment rentals. Additionally, the Company enters into certain firm commitments to transport natural gas production to market and to transport natural gas to its cogeneration and conventional steam generation facilities. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity is used or not.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
10. Commitments and Contingencies (Continued)

The table below shows the Company's future minimum payments under non-cancelable operating leases and other commitments as of December 31, 2011:

(in millions)	Total	2012	2013	2014	2015	2016	Thereafter
Operating leases(1)	$11.8	$2.8	$2.8	$2.6	$2.2	$1.4	$—
Drilling rig commitments(2)	7.0	7.0	—	—	—	—	—
Other commitments(3)	31.3	14.2	11.4	1.8	1.9	2.0	—
Firm natural gas transportation contracts(4)	263.5	29.7	30.2	32.7	32.6	32.5	105.8
Total	$313.6	$53.7	$44.4	$37.1	$36.7	$35.9	$105.8

(1) Includes operating leases related to office facilities, vehicles and aircraft.
(2) Excludes obligations related to rigs drilling on a well-by-well basis that can be released after drilling the current well without penalty.
(3) Includes primarily obligations related to natural gas purchases, cogeneration facility management services and equipment rentals.
(4) Includes a transportation agreement with Questar Pipeline Company for an average of 6,200 MMBtu/D of firm transportation over a period of eight years, based on the expectation that the expansion of the Chipeta Processing LLC natural gas plant expansion will be completed and transportation under this contract will begin July 1, 2012.

Uinta Crude Oil Sales Contract

The Company is a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of a minimum of 5,000 Bbl/D of its Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company's 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company's crude oil. Gross oil production from the Company's Uinta properties averaged approximately 3,390 Bbl/D in 2011. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the Company's crude oil sales customer in Utah could impact the marketability of a portion of the Company's Utah crude oil volumes. Please see Item 1A. Risk Factors—"We may not be able to deliver minimum crude oil volumes required by our sales contract."

E. Texas Gathering System

In July 2009, the Company closed on the financing of its E. Texas natural gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term natural gas gathering agreements for the E. Texas production which contained an embedded lease. The transaction was treated as a financing obligation. Accordingly, the $16.7 million net book value of the property is being depreciated over the remaining useful life of the asset and the cash received of $18.4 million was recorded as a financing obligation. A portion of payments under the agreements are recorded as gathering expense and a portion as interest expense, with the balance being recorded as a reduction to the financing obligation. There are no minimum payments required under these agreements. For the years ended December 31, 2011, 2010 and 2009 the Company incurred $5.3 million, $6.7 million and $2.0 million, respectively, under the agreements.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
10. Commitments and Contingencies (Continued)

Carry and Earning Agreement

On January 14, 2011, the Company entered into an amendment relating to certain contractual obligations to a third party co-owner of certain Piceance assets in Colorado. The amendment waives the $0.2 million penalty for each well not spud by February 2011 and requires the Company to reassign to such co-owner, by January 31, 2020, all of the interest acquired by the Company from the co-owner in each 160-acre tract in which the Company has not drilled and completed a well that is producing or capable of producing from a designated formation, or deeper formation, on January 1, 2020. The amendment also requires the Company to pay the first $9.0 million of costs incurred in connection with the construction of either an extension of the existing access road or a new access road, including the third party's 50% share. If by June 30, 2013 (which date may be extended until December 31, 2014 if road construction has commenced by June 30, 2013), the Company has not expended $9.0 million ($4.5 million of which would otherwise be such third party's responsibility) in road construction costs, then it will be obligated to pay the third party 50% of the difference between $12 million and the actual amount expended on road construction as of such date. Due to the need to obtain regulatory approvals, the Company has not yet commenced construction of either an extension of the existing access road or a new access road and may be unable to do so by June 30, 2013, thus triggering the payment obligation to the third party.

Environmental Matters

The Company has no material accrued environmental liabilities for its sites, including sites in which governmental agencies have designated the Company 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 material costs incurred.

Legal Matters

COGCC Order — On April 21, 2011, the Company received a proposed Order Finding Violation from the Colorado Oil and Gas Conservation Commission (COGCC) alleging that certain releases in late 2007 from a lined reserve pit located on a well pad in western Colorado violated COGCC regulations. Shortly thereafter, the Company entered into negotiations with the COGCC. While the Company denies that it violated any COGCC regulations in connection with the releases, on June 27, 2011, the COGCC approved and the Company later signed an Administrative Order on Consent under which the Company would pay $100,000, and fund a mutually acceptable public project in the amount of $73,000, in full satisfaction of the matter. The Company recorded these amounts in the second quarter of 2011 and paid $100,000 in July 2011. The Company expects to fund the mutually acceptable project during the first half of 2012.

BLM Settlement — On March 28, 2011, the Company entered into a settlement agreement with the Bureau of Land Management (BLM) resolving all claims by the BLM that the Company did not comply with BLM regulations relating to the operation and position of certain valves, and the submission of related site facility diagrams, in its Uinta operations. The settlement agreement confirmed that the Company promptly remediated the alleged noncompliance upon learning of it, and cooperated with the BLM's investigation, and that there is no evidence of any senior Company management knowledge of the alleged noncompliance, or of any environmental harm or loss of oil or royalty revenue resulting from such alleged noncompliance. The Company paid a $2.1 million civil penalty to the BLM under the settlement agreement in April 2011.

Royalty Payments — Certain of the Company's royalty payment calculations are being disputed. The Company believes that its royalty calculations are in accordance with applicable leases and other agreements, as well as applicable law. However, the disputed amounts that the Company may be required to pay are up to approximately $7.1 million.

Other — The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material effect on its financial position, results of operations or operating cash flows.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)

11. Oil and Natural Gas Properties, Buildings and Equipment

Oil and natural gas properties, buildings and equipment consist of the following:

	Year Ended December 31,	
(in thousands)	2011	2010
Oil and natural gas:		
Proved properties(1)	$3,257,321	$3,182,305
Unproved properties(2)	228,486	217,253
	3,485,807	3,399,558
Less accumulated depreciation, depletion and amortization	(962,154)	(757,264)
	2,523,653	2,642,294
Commercial and other:		
Machinery, drilling rigs, and equipment	22,509	24,988
Buildings and improvements	6,894	7,434
Vehicles	7,806	6,849
	37,209	39,271
Less accumulated depreciation	(29,469)	(25,773)
	7,740	13,498
	$2,531,393	$2,655,792

(1) Includes cogeneration facilities.

(2) Unproved properties includes acquisition costs for properties to which proved developed producing and proved undeveloped reserves are also attributed. At December 31, 2011, unproved properties included $14.8 million of acquisition costs for unevaluated properties. The Company assesses these properties annually and recorded impairments of $0.6 million, $0.0 million and $1.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Impairment of Oil and Natural Gas Properties

The Company reviews its oil and natural gas properties for impairment whenever events or circumstances indicate that their carry values may not be recoverable. During the years ended December 31, 2011, 2010 and 2009, the Company recorded impairments of oil and natural gas properties in continuing operations of $625.6 million, $0.0 million, and $1.0 million, respectively. Additionally, during the year ended December 31, 2009, the Company recorded an impairment of $9.6 million, which is recorded in discontinued operations.

In the fourth quarter of 2011, the Company recorded a non-cash impairment of $625.0 million related its E. Texas natural gas properties. The impairment was due to decreases in natural gas prices and, as a result, changes in the Company's development plans. In the fourth quarter of 2011, the NYMEX Henry Hub (HH) five-year future strip (the average of the settlement prices of the next 60 months' futures contracts) decreased approximately 15%. The carrying value of the Company's E. Texas assets prior to the impairment was $739.3 million. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, and discount rates commensurate with the risk associated with realizing the projected cash flows. Given the unobservable nature of these inputs, the nonrecurring fair value measurement of the E. Texas properties is deemed to use Level 3 inputs.

In March 2009, the Company entered into an agreement to sell its assets in the DJ. The transaction closed in April 2009. The Company recorded a non-cash impairment of $9.6 million related to the sale, which is aggregated within the $6.8 million earnings from discontinued operations, net of income tax, on its Statements of Operations for the year ended December 31, 2009.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
11. Oil and Natural Gas Properties, Buildings and Equipment (Continued)

If natural gas prices continue to decrease during 2012, the estimated undiscounted future cash flows of the Company's proved natural gas properties may not exceed the carry value and a non-cash impairment charge may be required to be recognized in future periods.

Dry Hole, Abandonment, and Impairment

During the years ended December 31, 2011, 2010, and 2009, the Company recorded an impairment of its drilling rigs in continuing operations of $4.3 million, $0 million, and $4.2 million, respectively. In the fourth quarter of 2011, the Company decided to sell and is actively marketing its three drilling rigs. As a result, the Company reduced the rigs' carrying value of $5.7 million to $1.4 million, consisting of the rigs' fair value less costs to sell. The fair value of the rigs is included in oil and natural gas properties (successful efforts basis), buildings and equipment, net on the Company's Balance Sheets at December 31, 2011. The fair value of the drilling rigs was determined using a market approach, considering comparative market data. Given the unobservable nature of these inputs, the nonrecurring fair value measurement of the drilling rigs is deemed to use Level 3 inputs. In the fourth quarter of 2009, subsequent to the approval of the Company's capital budget, the Company recorded a non-cash impairment to reduce the carrying value of a drilling rig to fair value. The carrying value of $7.5 million was written down to its fair value of $3.3 million. The fair value of the rig was determined using the present value of estimated cash flows. This model considered internal estimates of drilling and operating costs, technical and economic conditions, and a risk adjusted discount rate. Given the unobservable nature of these inputs, the nonrecurring fair value measurement of this rig is deemed to use Level 3 inputs.

In 2010, the Company recorded dry hole, abandonment, and impairment expense primarily due to a mechanical failure encountered on one well in the Piceance. The well was abandoned in favor of drilling a replacement well from the same well pad.

Capitalized Interest

Acquisition costs of proved undeveloped and unproved properties qualify for interest capitalization during a period if interest cost is incurred and activities necessary to bring the properties into a productive state are in progress. As wells are drilled in a field with proved undeveloped or unproved reserves, a portion of the acquisition costs are either re-designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, the Company determines the amount of the acquisition cost to re-designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

During 2011, the Company capitalized interest on its Piceance asset for the first half of 2011 and on its Permian asset for all of 2011, as development activities were ongoing. During 2010, the Company capitalized interest on its Piceance and Permian assets as development activities were ongoing. During 2009, the Company capitalized interest on its Piceance and E. Texas assets as development activities were ongoing. In the future, interest capitalization on acquisition costs will depend on whether or not development activities are ongoing. Development activities consist primarily of drilling wells and installing the necessary equipment for production to commence. Interest capitalization ceases when the wells have been completed. Interest cost is capitalized as a component of property cost for development projects that require greater than six months to be readied for their intended use.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)

12. Asset Retirement Obligations (AROs)

The following table summarizes the summarizes the activity for the Company's abandonment obligations:

	Year Ended December 31,	
(in thousands)	2011	2010
Beginning balance at January 1	$53,443	$43,487
Liabilities incurred	2,983	3,721
Liabilities settled	(1,803)	(1,832)
Liabilities assumed	119	3,498
Accretion expense	4,812	4,569
Revisions in estimated cash flows	4,465	—
Ending balance at December 31(1)	$64,019	$53,443

(1) The asset retirement obligation related to the Nevada Assets, which were held for sale as of December 31, 2011, was $0.7 million at December 31, 2011 and is included in the asset retirement obligations liability on the December 31, 2011 Balance Sheets. See Note 3 to the Financial Statements.

AROs reflect the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and natural gas properties. Inherent in the fair value calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance.

13. Supplemental Information about Oil & Natural Gas Producing Activities (Unaudited)

The reserve estimates were made in accordance with oil and natural gas reserve estimation and disclosure authoritative accounting guidance issued by the Financial Accounting Standards Board effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and natural gas reserve estimation and disclosure requirements with the requirements in the SEC's "Modernization of Oil and Gas Reporting" rule, which was also effective for annual reports for fiscal years ending on or after December 31, 2009.

The above-mentioned rules include updated definitions of proved oil and natural gas reserves, proved undeveloped oil and natural gas reserves, oil and natural gas producing activities, and other terms used in estimating proved oil and natural gas reserves. Proved oil and natural gas reserves were calculated based on the prices for oil and natural gas during the twelve month period before the reporting date, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. This average price is also used in calculating the aggregate amount and changes in future cash inflows related to the standardized measure of discounted future cash flows. In addition, the SEC generally requires that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
13. Supplemental Information about Oil & Natural Gas Producing Activities (Unaudited) (Continued)

Changes in Estimated Reserve Quantities

The following table sets forth the Company's estimates of its net proved, net proved developed, and net proved undeveloped oil and natural gas reserves as of December 31, 2011, 2010 and 2009, and changes in its net proved oil and natural gas reserves for the years then ended. For the years presented, the estimates of proved reserves and related valuations were based 100% on reports prepared by the Company's independent petroleum engineers, DeGolyer and MacNaughton (D&M).

	2011			2010			2009		
	Oil MBOE	Natural Gas MMcf	MBOE	Oil MBOE	Natural Gas MMcf	MBOE	Oil MBOE	Natural Gas MMcf	MBOE
Proved developed and undeveloped reserves:									
Beginning of year	166,181	630,192	271,213	129,940	632,178	235,303	125,251	724,135	245,940
Revision of previous estimates	(4,054)	(146,349)	(28,446)	4,288	(46,860)	(3,522)	2,786	(34,564)	(2,975)
Improved recovery	—	—	—	1,700	—	1,700	—	—	—
Extensions and discoveries	19,601	65,992	30,600	12,774	43,469	20,019	8,989	54,664	18,100
Property sales	—	—	—	—	—	—	—	(126,600)	(21,100)
Production	(9,041)	(23,907)	(13,025)	(7,925)	(23,989)	(11,923)	(7,186)	(22,657)	(10,962)
Purchase of reserves in place	13,193	8,351	14,584	25,404	25,394	29,636	100	37,200	6,300
End of year	185,880	534,279	274,926	166,181	630,192	271,213	129,940	632,178	235,303
Proved developed reserves:									
Beginning of year	88,917	268,566	133,678	82,870	255,520	125,456	74,616	361,575	134,879
End of year	107,849	221,606	144,783	88,917	268,566	133,678	82,870	255,520	125,456

Notable changes in proved reserves for the years ended December 31, 2011, 2010, 2009 included:

- Purchase of Reserves in Place. In 2011 and 2010 the Company acquired reserves of 14,584 MBOE, 29,636 MBOE and primarily in the Wolfberry trend in the Permian. See Note 2 to the Financial Statements. In 2009, the Company acquired reserves of 6,300 MBOE primarily in the Piceance.

- Extensions and Discoveries. In 2011, the Company had a total of 30,600 MBOE of extensions and discoveries, which were primarily due to successful drilling and completion activities in the Diatomite, McKittrick, Utah, Piceance and Permian assets. In 2010, the Company had a total of 20,019 MBOE of extensions and discoveries, which were primarily due to the successful drilling and completion activities in the Diatomite, Permian, Utah and E. Texas assets. In 2009, the Company had a total of 18,100 MBOE of extensions and discoveries, which were primarily due to the successful drilling and completion activities in the Diatomite and Piceance assets.

- Revisions to Previous Estimates. In 2011, the Company had negative revisions of 28,446 MBOE, which were primarily due to removing proved undeveloped reserves related to assets that reached aging limitations, as mandated by the SEC and negative performance revisions. Specifically, the decrease is due to a 19,632 MBOE decrease in E. Texas, a 5,779 MBOE decrease in Piceance and a 2,576 MBOE decrease in Utah. In 2010, the Company had negative revisions 3,522 MBOE, which were primarily due to negative performance revisions and the Company's future development plans.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
13. Supplemental Information about Oil & Natural Gas Producing Activities (Unaudited) (Continued)

Specifically, the decrease is due to a 3,666 MBOE decrease in E. Texas, a 3,890 MBOE decrease in the Piceance, and a 840 MBOE decrease in Uinta, offset by a 971 MBOE increase in the Permian and a 3,903 MBOE increase in California. In 2009, the Company had negative revisions of 2,975 MBOE, which were primarily due to negative performance revisions. Specifically, the decrease is due to a 9,108 MBOE decrease in E. Texas, offset by a 398 MBOE increase in California and 5,735 MBOE increase in Utah and Piceance.

- Property Sales. In 2009, the Company had total reserve sales of 21,100 MBOE from sale of its DJ assets. See Note 2 to the Financial Statements.

Standardized Measure of Discounted Future Net Cash Flows

Future oil and natural gas sales are calculated applying the prices used in estimating the Company's proved oil and natural gas reserves to the year-end quantities of those reserves. Future production and development costs, which include costs related to plugging of wells, removal of facilities and equipment, and site restoration, are calculated by estimating the expenditures to be incurred in producing and developing the proved oil and natural gas reserves at the end of each year, based on year-end costs and assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate year-end statutory income tax rates to the estimated future pre-tax net cash flows relating to proved oil and natural gas reserves, less the tax bases of the properties involved. The future income tax expenses give effect to income tax deductions, credits, and allowances relating to the proved oil and natural gas reserves. All cash flow amounts, including income taxes, are discounted at 10%.

The following table presents the standardized measure of discounted future net cash flows related to proved oil and natural gas reserves:

	Year Ended December 31,		
	2011	2010	2009
	(in thousands)		
Future cash inflows	$19,568,628	$14,354,627	$9,028,991
Future production costs	(5,226,044)	(4,446,183)	(3,826,832)
Future development costs	(1,975,429)	(1,789,001)	(1,159,465)
Future income tax expense	(3,770,512)	(2,272,184)	(969,771)
Future net cash flows	8,596,643	5,847,259	3,072,923
10% annual discount for estimated timing of cash flows	(4,561,364)	(3,048,103)	(1,627,176)
Standardized measure of discounted future net cash flows	$4,035,279	$2,799,156	$1,445,747
Average price during the 12-month period: (1)			
Oil ($/BOE)	$93.72	$69.04	$52.06
Natural gas ($/Mcf)	4.02	4.57	3.58
BOE ($/BOE)	$71.18	$52.93	$38.37

(1) Differences between the average benchmark prices and the average prices used in the calculation of the standardized measure are attributable to adjustments made for transportation, quality and basis differentials.

The present value (at a 10% annual discount) of future net cash flows from the Company’s proved reserves is not necessarily the same as the current market value of its estimated oil and natural gas reserves. The Company bases the estimated discounted future net cash flows from its proved reserves on prices and costs in effect on the day of estimate in accordance with the applicable accounting guidance. However, actual future net cash flows from its oil and natural gas properties will also be affected by factors such as actual prices the Company receives for oil and natural gas, the amount and timing of actual production, supply of and demand for oil and natural gas and changes in governmental regulations or taxation.

Table of Contents

BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
13. Supplemental Information about Oil & Natural Gas Producing Activities (Unaudited) (Continued)

The timing of both the Company's production and incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% annual discount factor the Company uses when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and natural gas industry in general.

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	Year ended December 31,		
	2011	2010	2009
	(in thousands)		
Standardized measure—beginning of year	$2,799,156	$1,445,747	$1,135,581
Sales of oil and natural gas produced, net of production costs	(599,679)	(406,390)	(353,052)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	1,473,454	1,724,212	637,882
Revisions of previous quantity estimates	(281,765)	(49,784)	(33,943)
Improved recovery	—	24,033	—
Extensions and discoveries	601,313	283,011	206,542
Change in estimated future development costs	(274,122)	(152,096)	(52,824)
Purchases of reserves in place	164,383	307,205	29,348
Sales of reserves in place	—	—	(138,265)
Development costs incurred during the period	433,660	144,086	110,200
Accretion of discount	383,418	184,917	131,745
Income taxes	(634,747)	(593,272)	(190,727)
Other	(29,792)	(112,513)	(36,740)
Net increase	1,236,123	1,353,409	310,166
Standardized measure—end of year	$4,035,279	$2,799,156	$1,445,747

The following table presents costs incurred in oil and natural gas property acquisition, exploration, and development activities:

	Year ended December 31,		
	2011	2010	2009
	(in thousands)		
Property acquisitions			
Proved properties	$149,158	$334,409	$13,497
Unproved properties	6,632	—	—
Development	544,114	320,927	138,168
Exploration	627	2,310	209
Total(1)	$700,531	$657,646	$151,874

(1)The total above does not reflect $29.1 million, $28.3 million, and $30.1 million of capitalized interest incurred in 2011, 2010, and 2009, respectively.

Table of Contents
BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)

14. Selected Quarterly Financial Data (Unaudited)

	Operating Revenues	Net (Loss) Earnings	Basic Net (Loss) Earnings Per Share(1)	Diluted Net (Loss) Earnings Per Share(1)
2011				
First Quarter	$197,486	$(52,497)	$(0.98)	$(0.98)
Second Quarter	242,709	105,166	1.93	1.90
Third Quarter	238,763	134,001	2.45	2.42
Fourth Quarter	240,600	(414,733)	(7.62)	(7.62)
	$919,558	$(228,063)	$(4.21)	$(4.21)
2010				
First Quarter	$166,012	$17,669	$0.34	$0.34
Second Quarter	164,457	89,023	1.65	1.64
Third Quarter	166,040	(3,023)	(0.06)	(0.06)
Fourth Quarter	180,001	(21,145)	(0.40)	(0.40)
	$676,510	$82,524	$1.54	$1.52

(1) The sum of the individual quarterly net (loss) earnings per common share amounts may not agree with year-to-date net (loss) earnings per common share as each quarterly computation is based on the weighted-average number of common shares outstanding during that period. Potentially dilutive securities were included in the computation of diluted net (loss) earnings per common share for each quarter in which the Company reported net earnings.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of December 31, 2011, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended (the Exchange Act).

Our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2011, our disclosure controls and procedures are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

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

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of our management and Directors; and

- provide reasonable assurance regarding prevention or the timely detection of unauthorized acquisition, or the use or disposition of our assets that could have a material effect on the financial statements.

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

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control—Integrated Framework, management concluded that our internal control over financial reporting was effective as of December 31, 2011. The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Table of Contents

PART III

Item 10. Directors and Executive Officers and Corporate Governance

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

Item 11. Executive Compensation

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

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

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

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

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

Item 14. Principal Accounting Fees and Services

The information called for by Item 14 is incorporated by reference from the information under the caption "Fees to Independent Registered Public Accounting Firms for 2011 and 2010" to be included in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this annual report:

(1) Financial Statements

All financial statements of the Registrant are set forth under Part II, Item 8 of this Annual Report on Form 10-K.

(2) Financial Statement Schedules

All financial statement schedules have been omitted because they are not applicable or not required, or the information required thereby is included in the Financial Statements or the notes thereto included in this Annual Report on Form 10-K.

(3) Exhibits

3.1	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, File No. 1-09735).
3.2	Restated Bylaws dated December 11, 2009 (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on December 11, 2009, File No. 1-09735).
4.1	Certificate of Designation, Preferences and Rights of Series B Junior Participating Preferred Stock (incorporated by reference to Exhibit A to the Registrant's Registration Statement on Form 8-A12B on December 7, 1999, File No. 001-09735).
4.2	Indenture, dated June 15, 2006, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, relating to subordinated debt securities (incorporated by reference to Exhibit 4.3 to the Registrant's Registration Statement on Form S-3 on June 15, 2006, File No. 1-9735).
4.3	First Supplemental Indenture, dated October 24, 2006, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, including the form of 8.25% senior subordinated note due 2016 (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on October 25, 2006, File No. 1-9735).
4.4	Indenture, dated June 15, 2006, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, relating to senior debt securities (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on May 29, 2009, File No. 1-09735).
4.5	First Supplemental Indenture, dated May 27, 2009, between Berry Petroleum Company and Wells Fargo Bank, National Association, as Trustee, including the form of 10.25% senior note due 2014 (incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on May 29, 2009, File No. 1-09735).
4.6	Second Supplemental Indenture, dated November 1, 2010, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, including the form of 6.75% senior note due 2020 (incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on November 1, 2010, File No. 1-09735).
4.7	Second Amended and Restated Credit Agreement, dated November 15, 2010, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed on November 17, 2010, File No. 1-9735).
4.8	First Amendment to the Second Amended and Restated Credit Agreement, dated April 13, 2011, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on April 13, 2011, File No. 1-9735).
4.9	Second Amendment to the Second Amended and Restated Credit Agreement, dated June 17, 2011, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto. (incorporated by reference to Exhibit 4.1 to the Registrant's Quarterly Report on

	Form 10-Q for the quarterly period ended September 30, 2011, File No. 1-9735).
4.10	Third Amendment to the Second Amended and Restated Credit Agreement, dated October 26, 2011, by and among Berry Petroleum Company, Wells Fargo Bank, N.A. and the other lenders party thereto (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on October 27, 2011, File No. 1-9735).
	The Registrant and its subsidiaries are party to other debt instruments not filed herewith under which the total amount of securities authorized does not exceed 10% of the total assets of Berry and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, Berry agrees to furnish a copy of such instruments to the SEC upon request.

10.1*	Carry and Earning Agreement, dated June 7, 2006, between Registrant and EnCana Oil & Gas (USA), Inc. (incorporated by reference to Exhibit 99.2 to the Registrant's Current Report on Form 8-K filed on June 19, 2006, File No. 1-9735).
10.2*	Crude Oil Supply Agreement between the Registrant and Holly Refining and Marketing Company - Woods Cross (incorporated by reference to Exhibit 10.22 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2006, File No. 1-0735).
10.3*	Crude Oil Purchase Contract dated March 20, 2009, between the Registrant and Tesoro Corporation (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File No. 1-09735).
10.4*	Crude Oil Purchase Contract dated September 24, 2009 between the Registrant and ExxonMobil Oil Corporation (incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, File No. 1-9735).
10.5*	Crude Oil Purchase Contract dated October 5, 2010 between the Registrant and ExxonMobil Oil Corporation (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010, File No. 1-9735).
10.6†	Amended and Restated 1994 Stock Option Plan (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-8 filed on August 20, 2002, File No. 333-98379).
10.7†	First Amendment to the Registrant's Amended and Restated 1994 Stock Option Plan dated as of June 23, 2006 (incorporated by reference to Exhibit 99.3 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.8†	Berry Petroleum Company 2005 Equity Incentive Plan (incorporated by reference to Exhibit 4.2 to the Registrant's Registration Statement on Form S-8 filed on July 29, 2005, File No. 333-127018).
10.9†	Form of Stock Option Agreement under the 2005 Equity Incentive Plan (incorporated by reference to Exhibit 4.3 to the Registrant's Registration Statement on Form S-8 filed on July 29, 2005, File No. 333-127018).
10.10†	Form of the Stock Appreciation Rights Agreement under the 2005 Equity Incentive Plan (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-8 filed on July 29, 2005, File No. 333-127018).
10.11†	Form of Stock Award Agreement under the 2005 Equity Incentive Plan (incorporated by reference to Exhibit 99.4 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.12†	Form of Amended and Restated Restricted Stock Award Agreement for directors under the 2005 Equity Incentive Plan (incorporated by reference to Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed on December 17, 2007, File No. 1-9735).
10.13†	Form of Amended and Restated Restricted Stock Award Agreement for officers under the 2005 Equity Incentive Plan (incorporated by reference to Exhibit 99.2 to the Registrant's Current Report on Form 8-K December 17, 2007, File No. 1-9735).
10.14†	Form of Award Grant under the Performance Share Award Program for select officers of the Company (incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on March 18, 2010, File No. 1-9735).
10.15†	Performance-based Restricted Stock Unit Award Agreement for Robert H. Heinemann under the 2005 Equity Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 18, 2010, File No. 1-9735).
10.16†	Performance-based Restricted Stock Unit Award Agreement for David D. Wolf under the 2005 Equity Incentive Plan (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on March 18, 2010, File No. 1-9735).
10.17†	Performance-based Restricted Stock Unit Award Agreement for Michael Duginski under the 2005 Equity Incentive Plan (incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on March 18, 2010, File No. 1-9735).

10.18†	Berry Petroleum Company 2010 Equity Incentive Plan (incorporated by reference to Exhibit 4.3 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.19†	Form of Restricted Stock Unit Award Agreement under the 2010 Equity Incentive Plan (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.20†	Form of Restricted Stock Unit Award Agreement for officers under the 2010 Equity Incentive Plan (incorporated by reference to Exhibit 4.5 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).

94

Table of Contents

10.21†	Form of Restricted Stock Unit Award Agreement for directors under the 2010 Equity Incentive Plan (incorporated by reference to Exhibit 4.6 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.22†	Form of Stock Option Agreement under the 2010 Equity Incentive Plan (incorporated by reference to Exhibit 4.7 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.23†	Form of Stock Appreciation Rights Agreement under the 2010 Equity Incentive Plan (incorporated by reference to Exhibit 4.8 to the Registrant's Registration Statement on Form S-8 filed on June 23, 2010, File No. 333-167698).
10.24†	Form of Amended and Restated Restricted Stock Unit Award Agreement for officers under the 2010 Equity Incentive Plan (incorporated by reference to Exhibit 99.2 to the Registrant's Current Report on Form 8-K filed on November 17, 2010, File No. 1-9735).
10.25†	Description of Short-Term Cash Incentive Plan of Registrant (incorporated by reference to Exhibit 10.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2006, File No. 1-9735).
10.26†	Non-Employee Director Deferred Stock and Compensation Plan (as amended and restated effective November 19, 2008) (incorporated by reference to exhibit 10.12 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2009, File No. 1-9735).
10.27†	Form of Change in Control Severance Protection Agreement dated August 24, 2006, by and between Registrant and selected employees of the Company (incorporated by reference to Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed on August 24, 2006, File No. 1-9735).
10.28†	Amended and Restated Employment Contract dated as of June 23, 2006 by and between the Registrant and Robert F. Heinemann (incorporated by reference to Exhibit 99.1 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.29†	Stock Award Agreement dated as of June 23, 2006 by and between the Registrant and Robert F. Heinemann (incorporated by reference to Exhibit 99.2 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.30†	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and David D. Wolf (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K/A filed on November 21, 2008, File No. 1-9735).
10.31†	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and Michael Duginski (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 21, 2008, File No. 1-9735).
10.32†	Form of Indemnity Agreement (incorporated by reference to Exhibit 99.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004, File No. 1-9735).
12.1	Ratio of Earnings to Fixed Charges.
23.1	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
23.2	Consent of DeGolyer and MacNaughton.
31.1	Certification of Chief Executive Officer pursuant to SEC Rule 13(a)-14(a).
31.2	Certification of Chief Financial Officer pursuant to SEC Rule 13(a)-14(a).
32.1	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code.
32.2	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code.
99.1	Report of DeGolyer and MacNaughton dated February 15, 2012 regarding the Registrant's reserves estimates.
99.2	Form of "B" Group Trust (incorporated by reference to Exhibit 28.3 to Amendment No. 1 to the Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240).

101	Interactive Data Files.

---

* Portions of this exhibit have been omitted pursuant to a request for confidential treatment.
† Management contract or compensatory plan or arrangement.

95

Table of Contents

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 28, 2012.

BERRY PETROLEUM COMPANY

/s/ ROBERT F. HEINEMANN	/s/ DAVID D. WOLF	/s/ JAMIE L. WHEAT
ROBERT F. HEINEMANN President, Chief Executive Officer and Director	DAVID D. WOLF Executive Vice President and Chief Financial Officer (Principal Financial Officer)	JAMIE L. WHEAT Controller (Principal Accounting Officer)

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

Name	Office	Date
/s/ MARTIN H. YOUNG, JR. Martin H. Young, Jr.	Chairman of the Board, Director	February 28, 2012
/s/ ROBERT F. HEINEMANN Robert F. Heinemann	President, Chief Executive Officer and Director	February 28, 2012
/s/ RALPH B. BUSCH, III Ralph B. Busch, III	Director	February 28, 2012
/s/ WILLIAM E. BUSH, JR. William E. Bush, Jr.	Director	February 28, 2012
/s/ STEPHEN L. CROPPER Stephen L. Cropper	Director	February 28, 2012
/s/ J. HERBERT GAUL, JR. J. Herbert Gaul, Jr.	Director	February 28, 2012
/s/ STEPHEN J. HADDEN Stephen J. Hadden	Director	February 28, 2012
/s/ THOMAS J. JAMIESON Thomas J. Jamieson	Director	February 28, 2012
/s/ J. FRANK KELLER J. Frank Keller	Director	February 28, 2012
/s/ MICHAEL S. REDDIN Michael S. Reddin	Director	February 28, 2012