DENBURY RESOURCES INC
Form 10-Q
August 08, 2012

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

FORM 10-Q

(Mark One)

þ Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 2012

o Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from _______ to ________

Commission file number: 001-12935

DENBURY RESOURCES INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-0467835 (I.R.S. Employer Identification No.)
5320 Legacy Drive, Plano, TX (Address of principal executive offices)	75024 (Zip Code)

Registrant's telephone number, including area code: (972) 673-2000

Not applicable
(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date.

Class	Outstanding at July 31, 2012
Common Stock, $.001 par value	391,196,837

Denbury Resources Inc.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Denbury Resources Inc.
Unaudited Condensed Consolidated Balance Sheets
(In thousands, except par value and share data)

	June 30, 2012	December 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 28,113	$ 18,693
Accrued production receivable	259,028	294,689
Trade and other receivables, net	170,536	164,446
Short-term investments	—	86,682
Derivative assets	57,764	47,402
Deferred tax assets	12,152	50,156
Other current assets	18,167	22,045
Total current assets	545,760	684,113
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	8,001,913	7,026,579
Unevaluated	777,141	1,157,106
CO_2 properties	649,596	596,003
Pipelines and plants	1,875,847	1,701,756
Other property and equipment	396,847	157,674
Less accumulated depletion, depreciation, amortization, and impairment	(2,947,035)	(2,627,493)
Net property and equipment	8,754,309	8,011,625
Derivative assets	36,672	29
Goodwill	1,363,547	1,236,318
Other assets	235,128	252,339
Total assets	$ 10,935,416	$ 10,184,424
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 459,416	$ 429,336
Oil and gas production payable	187,205	197,092
Derivative liabilities	1,816	26,523
Current maturities of long-term debt	36,168	8,316
Total current liabilities	684,605	661,267
Long-term liabilities		
Long-term debt, net of current portion	2,942,070	2,669,729
Asset retirement obligations	86,572	88,726
Derivative liabilities	—	18,872
Deferred taxes	2,047,967	1,918,576

Other liabilities		21,005			20,756	
Total long-term liabilities		5,097,614			4,716,659	
Commitments and contingencies (Note 6)						
Stockholders' equity						
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding		—			—	
Common stock, $.001 par value, 600,000,000 shares authorized; 405,005,251 and 402,946,070 shares issued, respectively		405			403	
Paid-in capital in excess of par		3,113,042			3,090,374	
Retained earnings		2,234,807			1,909,475	
Accumulated other comprehensive loss		(383	)		(418	)
Treasury stock, at cost, 13,961,181 and 13,965,673 shares, respectively		(194,674	)		(193,336	)
Total stockholders' equity		5,153,197			4,806,498	
Total liabilities and stockholders' equity	$	10,935,416		$	10,184,424	

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Denbury Resources Inc.

Unaudited Condensed Consolidated Statements of Operations
(In thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenues and other income				
Oil, natural gas, and related product sales	$592,141	$591,099	$1,225,642	$1,097,291
CO_2 sales and transportation fees	5,301	5,343	12,096	10,267
Interest income and other income	4,339	4,955	9,159	8,004
Total revenues and other income	601,781	601,397	1,246,897	1,115,562
Expenses				
Lease operating expenses	124,511	126,085	262,475	249,882
Marketing expenses	12,218	6,270	23,048	11,573
CO_2 discovery and operating expenses	1,062	1,693	7,267	3,639
Taxes other than income	38,812	39,632	82,506	72,115
General and administrative	34,826	28,709	71,433	71,028
Interest, net of amounts capitalized of $18,475, $13,194, $37,920 and $24,151, respectively	41,604	42,249	77,918	91,026
Depletion, depreciation, and amortization	132,289	103,495	253,184	197,089
Derivatives income	(139,109)	(172,904)	(93,834)	(2,154)
Loss on early extinguishment of debt	—	348	—	16,131
Impairment of assets	215	—	17,515	—
Other expenses	12,552	2,018	23,272	4,377
Total expenses	258,980	177,595	724,784	714,706
Income before income taxes	342,801	423,802	522,113	400,856
Income tax provision				
Current income taxes	784	12,028	29,492	11,180
Deferred income taxes	130,152	152,528	167,289	144,620
Net income	$211,865	$259,246	$325,332	$245,056
Net income per common share – basic	$0.55	$0.65	$0.84	$0.62
Net income per common share – diluted	$0.54	$0.64	$0.83	$0.61
Weighted average common shares outstanding				
Basic	387,159	398,631	386,764	398,032
Diluted	390,702	403,919	390,823	403,703

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Denbury Resources Inc.

Unaudited Condensed Consolidated Statements of Comprehensive Operations
(In thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net income	$ 211,865	$ 259,246	$ 325,332	$ 245,056
Other comprehensive income (loss), net of income tax:				
Net unrealized loss on available-for-sale securities, net of tax of $4,375 and $1,824, respectively	—	(7,139)	—	(2,976)
Interest rate lock derivative contracts reclassified to income, net of tax of $10, $10, $21 and $21, respectively	17	18	35	35
Total other comprehensive income (loss)	17	(7,121)	35	(2,941)
Comprehensive income	$ 211,882	$ 252,125	$ 325,367	$ 242,115

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Resources Inc.

Unaudited Condensed Consolidated Statements of Cash Flows
(In thousands)

	Six Months Ended June 30, 2012	2011
Cash flows from operating activities		
Net income	$ 325,332	$ 245,056
Adjustments needed to reconcile to net cash flow provided by operations:		
Depletion, depreciation, and amortization	253,184	197,089
Deferred income taxes	167,289	144,620
Stock-based compensation	15,249	18,132
Noncash fair value derivative adjustments	(87,686)	(11,451)
Loss on early extinguishment of debt	—	16,131
Amortization of debt issuance costs and discounts	7,347	9,613
Impairment of assets	17,515	—
Other, net	15,835	(3,915)
Changes in operating assets and liabilities:		
Accrued production receivable	35,466	(35,068)
Trade and other receivables	(10,769)	(10,142)
Other current and long-term assets	6,851	(21,036)
Accounts payable and accrued liabilities	28,256	(48,471)
Oil and natural gas production payable	(7,985)	30,135
Other liabilities	(33,264)	(7,340)
Net cash provided by operating activities	732,620	523,353
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(574,008)	(471,601)
Acquisitions of oil and natural gas properties	(154,366)	(32,482)
CO2 capital expenditures	(53,313)	(32,042)
Pipelines and plants capital expenditures	(169,675)	(98,237)
Purchases of other assets	(10,748)	(20,372)
Net proceeds from sales of oil and natural gas properties and equipment	32,302	18,432
Proceeds from sale of short-term investments	83,545	—
Other	(2,961)	3,462
Net cash used for investing activities	(849,224)	(632,840)
Cash flows from financing activities:		
Bank repayments	(400,000)	(130,000)
Bank borrowings	535,000	130,000
Repayment of senior subordinated notes	—	(525,000)
Premium paid on repayment of senior subordinated notes	—	(13,137)
Net proceeds from issuance of senior subordinated notes	—	400,000
Net proceeds from issuance of common stock	8,055	9,203
Costs of debt financing	(11)	(13,274)
Other	(17,020)	(8,382)
Net cash provided by (used for) financing activities	126,024	(150,590)
Net increase (decrease) in cash and cash equivalents	9,420	(260,077)

Cash and cash equivalents at beginning of period		18,693		381,869
Cash and cash equivalents at end of period	$	28,113	$	121,792

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is a growing independent oil and natural gas company. We are the largest combined oil and natural gas producer in both Mississippi and Montana, own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of our acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with our most significant emphasis on our CO_2 tertiary recovery operations.

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") and do not include all of the information and footnotes required by Accounting Principles Generally Accepted in the United States ("U.S. GAAP") for complete financial statements. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2011. Unless indicated otherwise or the context requires, the terms "we," "our," "us," "Company," or "Denbur refer to Denbury Resources Inc. and its subsidiaries.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year-end and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the year. In management's opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair statement of our consolidated financial position as of June 30, 2012, our consolidated results of operations for the three and six months ended June 30, 2012 and 2011, and our consolidated cash flows for the six months ended June 30, 2012 and 2011.

Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter. On the Unaudited Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2011, "Taxes other than income" is a new line item and includes oil and natural gas ad valorem taxes, which were reclassified from "Lease operating expenses," franchise taxes and property taxes on buildings, which were reclassified from "General and administrative," oil and natural gas production taxes, which were reclassified from "Production taxes and marketing expenses" used in prior reports and CO_2 property ad valorem and production taxes, which were classified from "CO_2 discovery and operating expenses." Such reclassifications had no impact on our reported total expenses or net income.

Net Income per Common Share

Basic net income per common share is computed by dividing net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but also considers the impact to net income and common shares of the potential dilution from stock options, stock appreciation rights ("SARs"), nonvested restricted stock, and nonvested performance equity awards. For the three and six months ended June 30, 2012 and 2011, there were no adjustments to net income for purposes of calculating diluted net income per common share.

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Notes to Unaudited Condensed Consolidated Financial Statements

The following is a reconciliation of the weighted average shares used in the basic and diluted net income per common share calculations for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2012	2011	2012	2011
Basic weighted average common shares	387,159	398,631	386,764	398,032
Potentially dilutive securities:				
Stock options and SARs	2,644	3,946	2,987	4,251
Performance equity awards	32	23	74	12
Restricted stock	867	1,319	998	1,408
Diluted weighted average common shares	390,702	403,919	390,823	403,703

Basic weighted average common shares excludes 3.5 million and 3.8 million shares for the three and six months ended June 30, 2012, respectively, and 3.4 million and 3.6 million shares for the three and six months ended June 30, 2011, respectively, of nonvested restricted stock. As these restricted shares vest or become retirement eligible, they will be included in the shares outstanding used to calculate basic net income per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares, the nonvested restricted stock is included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity.

The following securities could potentially dilute earnings per share in the future, but were excluded from the computation of diluted net income per share as their effect would have been antidilutive:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2012	2011	2012	2011
Stock options and SARs	3,866	2,412	3,522	2,297
Restricted stock	109	24	60	15
Total	3,975	2,436	3,582	2,312

Short-Term Investments

Short-term investments are available-for-sale securities recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. At December 31, 2011, short-term investments consisted entirely of our investment in Vanguard Natural Resources LLC ("Vanguard") common units obtained as partial consideration for the sale of our interests in Encore Energy Partners LP to a subsidiary of Vanguard on December 31, 2010. We received distributions of $1.7 million and $3.5 million on the Vanguard common units we owned during the three and six months ended June 30, 2011, respectively, which are included in "Interest income and other income" on our Unaudited Condensed Consolidated Statements of Operations. During January 2012, the Company sold its investment in Vanguard for cash consideration of $83.5 million, net of related transaction fees. The Company recognized a pretax loss on the sale of $3.1 million, which is included in "Other expenses" on our Unaudited Condensed Consolidated Statements of Operations for the six months ended June 30, 2012.

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Notes to Unaudited Condensed Consolidated Financial Statements

Goodwill

The following table summarizes the changes in Denbury's goodwill for the period indicated:

In thousands	Six Months Ended June 30, 2012
Balance, beginning of period	$1,236,318
Goodwill related to the acquisition of interests in Thompson Field(1)	127,229
Balance, end of period	$1,363,547

(1) See Note 2, Acquisitions and Divestitures, for additional information regarding goodwill associated with Thompson Field.

Recently Adopted Accounting Pronouncements

Comprehensive Income. In June 2011, the Financial Accounting Standards Board ("FASB") issued ASU 2011-05, Presentation of Comprehensive Income ("ASU 2011-05"). ASU 2011-05 requires the presentation of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. ASU 2011-05 was effective for Denbury beginning January 1, 2012. Since ASU 2011-05 only amended presentation requirements, it did not have a material effect on our consolidated financial statements.

Fair Value. In May 2011, the FASB issued ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs ("ASU 2011-04"). ASU 2011-04 amends the Financial Accounting Standards Board Codification ("FASC") Fair Value Measurements topic by providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurements and expands the fair value disclosure requirements, particularly for Level 3 fair value measurements. ASU 2011-04 was effective for Denbury beginning January 1, 2012. The adoption of ASU 2011-04 did not have a material effect on our consolidated financial statements, but did require additional disclosures. See Note 5, Fair Value Measurements.

Note 2. Acquisitions and Divestitures

Acquisitions

June 2012 Acquisition of Reserves in the Gulf Coast region at Thompson Field

In June 2012, we acquired a nearly 100% working interest and 84.7% net revenue interest in Thompson Field for $366.2 million after preliminary closing adjustments. The field is located approximately 18 miles west of Hastings Field, which is an enhanced oil recovery ("EOR") field that Denbury is currently flooding with CO2, and is the current terminus of the Green Pipeline which transports CO2 from the Jackson Dome, located near Jackson, Mississippi. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is also expected to be an ideal candidate for a CO2 flood. Under the terms of the Thompson Field acquisition agreement, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d after the initiation of CO_2 injection.

Notes to Unaudited Condensed Consolidated Financial Statements

This acquisition meets the definition of a business under the FASC Business Combinations topic. As such, Denbury estimated the fair value of assets acquired and liabilities assumed as of June 1, 2012, the closing date of the acquisition. The FASC Fair Value Measurements and Disclosures topic defines fair value as 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 (often referred to as the “exit price”). The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific assumptions should not impact the measurement of fair value unless those assumptions are consistent with market participant views.

In applying these accounting principles, Denbury estimated the fair value of the assets acquired less liabilities assumed on the acquisition date to be approximately $238.9 million. This measurement resulted in the recognition of goodwill of approximately $127.2 million, which represents the excess of the cash paid to acquire the field over the acquisition date estimated fair value. This resultant goodwill is due primarily to two factors. The first factor is the decrease in average NYMEX oil futures prices between the date of signing the purchase agreement on April 24, 2012 and closing the purchase on June 1, 2012. The second factor is the fair value assigned to the estimated oil reserves recoverable through a CO2 EOR project. By building an 18 mile extension of the Green Pipeline, Denbury has access to its CO2 reserves at Jackson Dome, one of the few known significant natural sources of CO2 in the United States, and the largest known source east of the Mississippi River, allowing Denbury to carry out CO2 EOR activities in this field at a lower cost than other market participants. However, the FASC Fair Value Measurements and Disclosures does not allow entity-specific assumptions in the measurement of fair value. Therefore, we estimated the fair value of the oil reserves recoverable through CO2 EOR using a higher estimated cost of CO2 to other market participants, which lowers the discounted net revenue stream used in making the fair value estimate related to this field.

The fair value of Thompson Field assets acquired and liabilities assumed was based on significant inputs not observable in the market, which FASC Fair Value Measurements and Disclosures topic defines as Level 3 inputs. Key assumptions include (1) NYMEX oil futures prices (this input is observable), (2) estimated quantities of oil reserves, (3) projections of future rates of production, (4) timing and amount of estimated future development and operating costs, (5) projected cost of CO2 to a market participant, (6) projected recovery factors, and (7) risk-adjusted discount rates. The fair value of the oil and natural gas properties was determined using a risk-adjusted after-tax discounted cash flow analysis. Denbury applies full cost accounting rules, and all of the goodwill is deductible for tax purposes as property cost.

The following table presents a summary of the preliminary fair value of the Thompson Field assets acquired and liabilities assumed.

In thousands	
Consideration:	
Cash payment (1)	$366,178
Total consideration	366,178
Less: Fair value of assets acquired and liabilities assumed: (2)	
Oil and natural gas properties	
Proved	232,467
Unevaluated	4,151
Pipelines and plants	2,000
Other assets	3,637
Asset retirement obligations	(3,306)

	238,949
Goodwill	$127,229

(1) See Divestitures below for additional information regarding restricted cash and the like-kind exchange transaction utilized to fund the purchase.

Notes to Unaudited Condensed Consolidated Financial Statements

(2) Fair value of the assets acquired and liabilities assumed is preliminary, pending final closing adjustments and further evaluation of reserves and asset retirement obligations.

Pro Forma Information

Had the Thompson Field acquisition occurred on January 1, 2011, our combined pro forma revenues and net income for the three and six months ended June 30, 2012 and 2011, would have been as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share amounts	2012	2011	2012	2011
Pro forma total revenues	$617,500	$617,446	$1,286,717	$1,144,976
Pro forma net income	218,027	264,543	340,950	254,074
Pro forma net income per common share				
Basic	$0.56	$0.66	$0.88	$0.64
Diluted	0.56	0.65	0.87	0.63

August 2011 Acquisition of Reserves in Rocky Mountain Region at Riley Ridge

In August 2011, we acquired the remaining 57.5% working interest in the Riley Ridge Federal Unit ("Riley Ridge"), located in the LaBarge Field of southwestern Wyoming. Riley Ridge contains natural gas resources, as well as helium and CO2 resources. The purchase included a 57.5% interest in a gas plant which will separate the helium and natural gas from the commingled gas stream, and interests in certain surrounding properties. We previously acquired the other 42.5% interest in Riley Ridge and the gas plant in October 2010. The purchase price for the August 2011 acquisition was approximately $214.8 million after closing adjustments, including a $15.0 million deferred payment to be made at the time the Riley Ridge gas plant is operational and meets specific performance conditions. The gas plant is currently undergoing readiness testing, and we expect it to become operational in December 2012 or early 2013.

The August 2011 acquisition of Riley Ridge meets the definition of a business under the FASC Business Combinations topic. The fair values assigned to assets acquired and liabilities assumed in the August 2011 acquisition have been finalized and no adjustments have been made to fair value amounts previously disclosed in our Form 10-K for the period ended December 31, 2011. Because the Riley Ridge plant is not yet operational, current production at the field is negligible. As a result, pro forma information has not been disclosed due to the immateriality of revenues and expenses during 2011.

Divestitures

On February 29, 2012, we completed the sale of certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $155.0 million to a privately held entity in which a member of our Board of Directors serves as chairman of the board, in a sale for which there was a competing bid contained in a multi-property purchase proposal. We realized net proceeds of $141.8 million, after final closing adjustments. The sale had an effective date of December 1, 2011 and consequently, operating revenues of $13.5 million after the effective date, net of capital and lease operating expenditures, along with any other purchase price adjustments, were adjustments to the selling price.

On April 9, 2012, we completed the sale of certain non-operated assets in the Paradox Basin of Utah for $75.0 million. The sale had an effective date of January 1, 2012 and proceeds received after consideration of closing adjustments totaled $68.5 million. Closing adjustments included operating net revenues after January 1, 2012, net of capital and lease operating expenditures, along with other purchase price adjustments.

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Notes to Unaudited Condensed Consolidated Financial Statements

We did not record a gain or loss on either of the above sales of properties in accordance with the full cost method of accounting.

Of the proceeds from these property sales before final closing adjustments, $212.5 million was paid directly to a qualified intermediary and later released to fund a portion of the acquisition cost of Thompson Field (see June 2012 Acquisition of Reserves in the Gulf Coast region at Thompson Field above). Since the $212.5 million in cash proceeds was never held by, or paid directly to, Denbury's bank account, this amount is not reflected as a receipt of net proceeds from the sale of oil and natural gas properties and equipment, nor as a cash payment to purchase oil and natural gas properties in the investing activity in our Consolidated Statement of Cash Flows.

Note 3. Long-Term Debt

The following table shows the components of our long-term debt:

In thousands	June 30, 2012	December 31, 2011
Bank Credit Facility	$520,000	$385,000
9½% Senior Subordinated Notes due 2016, including premium of $10,486 and $11,854, respectively	235,406	236,774
9¾% Senior Subordinated Notes due 2016, including discount of $15,711 and $17,854, respectively	410,639	408,496
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6 % Senior Subordinated Notes due 2021	400,000	400,000
Other Subordinated Notes, including premium of $29 and $33, respectively	3,835	3,840
NEJD Pipeline financing	161,707	163,677
Free State Pipeline financing	78,878	79,597
Capital lease obligations	171,500	4,388
Total	2,978,238	2,678,045
Less current obligations	(36,168)	(8,316)
Long-term debt and capital lease obligations	$2,942,070	$2,669,729

The parent company, Denbury Resources Inc. ("DRI"), is the sole issuer of all of our outstanding senior subordinated notes. DRI has no independent assets or operations. Certain of DRI's subsidiaries guarantee our debt, and each such subsidiary guarantor is 100% owned by DRI; and the guarantees are full and unconditional and joint and several obligations of the subsidiary guarantors; any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries.

Bank Credit Facility

In March 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A. as administrative agent, and other lenders party thereto (as amended the "Bank Credit Agreement"). Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined semi-annually on or prior to May 1 and November 1 of each year, and is subject to requested special redeterminations. The borrowing base is adjusted at the banks' discretion and is based in part upon certain external factors over which we have no control. The weighted average interest rate on borrowings under the credit facility, evidenced by the Bank Credit Agreement (the "Bank

Credit Facility") was 2.0% for the six months ended June 30, 2012. We incur a commitment fee on the unused portion of the Bank Credit Facility of either 0.375% or 0.5%, based on the ratio of outstanding borrowings under the Bank Credit Facility to the borrowing base. The Bank Credit Agreement is scheduled to mature in May 2016.

Notes to Unaudited Condensed Consolidated Financial Statements

In April 2012, we entered into the Seventh Amendment to the Bank Credit Agreement (the "Seventh Amendment"). Under the Seventh Amendment, we increased the amount of additional permitted subordinated debt (other than refinancing debt) from $300.0 million to $650.0 million. At the same time, the banks reaffirmed Denbury's borrowing base of $1.6 billion under the Bank Credit Facility until the next redetermination, which is scheduled to occur on or around November 1, 2012.

In July 2012, we entered into the Eighth Amendment to the Bank Credit Agreement (the "Eighth Amendment"). The Bank Credit Agreement permits the Company to incur capital lease obligations in an aggregate amount outstanding at any time not to exceed $300 million. The Bank Credit Agreement permits the Company to incur up to $40 million of other unsecured debt, and prior to the effectiveness of the Eighth Amendment capital leases would have been captured in this permitted debt basket. The Bank Credit Agreement was amended concurrent with the Company's change in classification of equipment leases from operating to capital in the second quarter of 2012 (see Capital Leases below), and the Eighth Amendment included the granting by the lenders of a waiver of any applicable violations of the provisions of the Bank Credit Agreement resulting from such correction and the Company's recording of its equipment leases as debt.

6 % Senior Subordinated Notes due 2021

In February 2011, we issued $400.0 million of 6 % Senior Subordinated Notes due 2021 ("2021 Notes"). The 2021 Notes, which carry a coupon rate of 6.375%, were sold at par. The net proceeds of $393.0 million were used to repurchase a portion of our outstanding 2013 Notes and 2015 Notes (see Redemption of our 2013 and 2015 Notes below).

Redemption of our 2013 and 2015 Notes

Pursuant to cash tender offers, during March 2011, we repurchased $169.6 million in principal of our 7½% Senior Subordinated Notes due 2013 ("2013 Notes") at 100.625% of par, and $220.9 million in principal of our 7½% Senior Subordinated Notes due 2015 ("2015 Notes") at 104.125% of par. We called the remaining 2013 Notes and 2015 Notes, repurchasing all of the remaining outstanding 2015 Notes ($79.1 million) at 103.75% of par on March 21, 2011 and all of the remaining outstanding 2013 Notes ($55.4 million) at par on April 1, 2011. We recognized a $0.3 million and $16.1 million loss during the three and six months ended June 30, 2011, respectively, associated with the debt repurchases, which are included in our Unaudited Condensed Consolidated Statements of Operations under the caption "Loss on early extinguishment of debt."

Capital Lease Obligations

During the second quarter of 2012, the Company corrected the accounting for its equipment leases from operating leases to capital leases to comply with ASC Topic 840, Leases as a result of the consideration of nonperformance-related default covenants included in its equipment lease agreements. The Company recorded a cumulative adjustment to establish the capital lease assets as "Other property and equipment" ($155.6 million) and the capital lease obligations as "Long-term debt" ($138.9 million) and "Current maturities of long-term debt" ($25.1 million) on the accompanying Unaudited Condensed Consolidated Balance Sheets. The Company also recognized the cumulative pre-tax impact of $8.4 million ($5.2 million after tax) as "Other expenses" on the accompanying Unaudited Condensed Consolidated Statements of Operations. Because the amounts involved were not material to the Company's financial statements in any individual prior period, and the cumulative impact is not material to the estimated results of operations for the year ending December 31, 2012, the Company recorded the cumulative effect of correcting these items during the three months ended June 30, 2012.

Note 4. Derivative Instruments

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts; therefore, the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the cash settlements of expired contracts, are shown under “Derivatives income” in our Unaudited Condensed Consolidated Statements of Operations.

Notes to Unaudited Condensed Consolidated Financial Statements

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production approximately 12 to 18 months in advance, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending in those future periods in light of current worldwide economic uncertainties and commodity price volatility.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification. We only enter into commodity derivative contracts with parties that are lenders under our Bank Credit Agreement.

The following is a summary of “Derivatives income” included in the accompanying Unaudited Condensed Consolidated Statements of Operations for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2012	2011	2012	2011
Oil				
Payment on settlements of derivative contracts	$ 709	$ 16,972	$ 8,939	$ 22,000
Fair value adjustments to derivative contracts – income	(140,923)	(187,194)	(98,478)	(20,130)
Total derivatives expense (income) – oil	(140,214)	(170,222)	(89,539)	1,870
Natural Gas				
Receipt on settlements of derivative contracts	(7,991)	(6,030)	(15,031)	(12,646)
Fair value adjustments to derivative contracts – expense	9,096	3,348	10,736	8,622
Total derivatives expense (income) – natural gas	1,105	(2,682)	(4,295)	(4,024)
Derivatives income	$ (139,109)	$ (172,904)	$ (93,834)	$ (2,154)

Notes to Unaudited Condensed Consolidated Financial Statements

Commodity Derivative Contracts Not Classified as Hedging Instruments

The following tables present outstanding commodity derivative contracts with respect to future production as of June 30, 2012:

				Contract Prices(2)			
					Weighted Average Price		
Year	Months	Type of Contract	Volume(1)	Range	Swap	Floor	Ceiling
Oil Contracts:							
2012	July – Sept	Swap	625	$ 80.28 – 81.75	$ 81.04	$ —	$ —
		Collar	53,000	80.00 – 140.65	—	80.00	128.57
		Put	625	65.00 – 65.00	—	65.00	—
	Total July – Sept 2012		54,250				
	Oct – Dec	Swap	625	$ 80.28 – 81.75	$ 81.04	$ —	$ —
		Collar	53,000	80.00 – 140.65	—	80.00	128.57
		Put	625	65.00 – 65.00	—	65.00	—
	Total Oct – Dec 2012		54,250				
2013	Jan – Mar	Swap	—	$ —	$ —	$ —	$ —
		Collar	55,000	70.00 – 117.00	—	70.00	110.32
		Put	—	—	—	—	—
	Total Jan – Mar 2013		55,000				
	Apr – June	Swap	—	$ —	$ —	$ —	$ —
		Collar	50,000	75.00 – 124.20	—	75.00	116.92
		Put	—	—	—	—	—
	Total Apr – June 2013		50,000				
	July – Sept	Swap	—	$ —	$ —	$ —	$ —
		Collar	50,000	75.00 – 133.10	—	75.00	122.14
		Put	—	—	—	—	—
	Total July – Sept 2013		50,000				

	Oct – Dec	Swap	—	$	—	$	—	$	—	$	—
		Collar	38,000		80.00 – 127.50		—		80.00		123.49
		Put	—		—		—		—		—
	Total Oct – Dec 2013		38,000								
Natural Gas Contracts:											
2012	July – Dec	Swap	20,000	$	6.30 – 6.85	$	6.53	$	—	$	—
		Collar	—		—		—		—		—
		Put	—		—		—		—		—
	Total July – Dec 2012		20,000								

(1) Contract volumes are stated in Bbl/d and MMBtu/d for oil and natural gas contracts, respectively.
(2) Contract prices are stated in $/Bbl and $/MMBtu for oil and natural gas contracts, respectively.

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Notes to Unaudited Condensed Consolidated Financial Statements

Additional Disclosures about Derivative Instruments

At June 30, 2012 and December 31, 2011, we had derivative financial instruments recorded in our Unaudited Condensed Consolidated Balance Sheets as follows:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) June 30, 2012	December 31, 2011
		In thousands	
Derivatives not designated as hedging instruments:			
Derivative asset			
Crude oil contracts	Derivative assets – current	$ 44,550	$ 23,452
Natural gas contracts	Derivative assets – current	13,214	23,950
Crude oil contracts	Derivative assets – long-term	36,672	29
Derivative liability			
Crude oil contracts	Derivative liabilities – current	(574)	(22,610)
Deferred premiums(1)	Derivative liabilities – current	(1,242)	(3,913)
Crude oil contracts	Derivative liabilities – long-term	—	(18,702)
Deferred premiums(1)	Derivative liabilities – long-term	—	(170)
Total derivatives not designated as hedging instruments		$ 92,620	$ 2,036

(1) Deferred premiums payable relate to various oil floor contracts and are payable on a monthly basis through January 2013.

Note 5. Fair Value Measurements

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 (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1 – Quoted prices in active markets for identical assets or liabilities as of the reporting date.

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil and natural gas derivatives that are based on NYMEX pricing. The Company's costless-collars are valued using the Black-Scholes model, an industry standard option valuation model, that takes into account inputs such as contractual prices for the underlying instruments, including maturity, quoted forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Notes to Unaudited Condensed Consolidated Financial Statements

- Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Instruments in this category include non-exchange-traded natural gas derivatives swaps that are based on regional pricing other than NYMEX (i.e., Houston ship channel). The Company's basis swaps are estimated using discounted cash flow calculations based upon forward commodity price curves. Significant increases or decreases in forward commodity price curves would result in a significantly higher or lower fair value measurement.

We adjust the valuations from the valuation model for nonperformance risk, using our estimate of the counterparty's credit quality for asset positions and Denbury's credit quality for liability positions. Denbury uses multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of the periods indicated:

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
June 30, 2012				
Assets				
Oil and natural gas derivative contracts	$—	$81,222	$ 13,214	$94,436
Liabilities				
Oil and natural gas derivative contracts	—	(574)	—	(574)
Total	$—	$80,648	$ 13,214	$93,862
December 31, 2011				
Assets				
Short-term investments	$86,682	$—	$ —	$86,682
Oil and natural gas derivative contracts	—	23,481	23,950	47,431
Liabilities				
Oil and natural gas derivative contracts	—	(41,312)	—	(41,312)
Total	$86,682	$(17,831)	$ 23,950	$92,801

Since we do not use hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in "Derivatives income" in the accompanying Unaudited Condensed Consolidated Statements of Operations.

Notes to Unaudited Condensed Consolidated Financial Statements

Level 3 Fair Value Measurements

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following table summarizes the changes in the fair value of our Level 3 assets for the three and six months ended June 30, 2012 and 2011:

In thousands	Three Months Ended June 30, 2012	2011	Six Months Ended June 30, 2012	2011
Balance, beginning of period	$22,310	$15,346	$23,950	$16,478
Unrealized gains (losses) on commodity derivative contracts included in earnings	(1,105)	(7,386)	4,295	(7,076)
Receipts on settlement of commodity derivative contracts	(7,991)	(1,322)	(15,031)	(2,764)
Balance, end of period	$13,214	$6,638	$13,214	$6,638

We utilize an income approach to value our natural gas swap arrangements, generally the industry standard valuation technique for a commodity swap contract. We obtain and ensure the appropriateness of the natural gas forward pricing curve, the most significant input to the calculation, and the fair value estimate is prepared and reviewed on a quarterly basis.

The following table details fair value inputs related to our Level 3 natural gas financial measurements:

In thousands	Fair Value at 6/30/2012	Valuation Technique	Unobservable Input	Range
Natural gas derivative contracts	$ 13,214	Discounted Cash Flow	Forward commodity price curve	(a)

(a) The derivative instruments detailed in this category include non-exchange-traded natural gas derivatives swaps that are valued based on regional pricing other than NYMEX. The regional pricing sources utilized for these instruments include the following (forward pricing ranges represent the high and low price expected to be received within the settlement period):

Pricing Index	Settlement Period	Forward Pricing Range
TETCO M1	7/1/2012 – 12/31/2012	$2.77/MMBtu – $3.39/MMBtu
Houston Ship Channel	7/1/2012 – 12/31/2012	$2.77/MMBtu – $3.29/MMBtu
Natural Gas – Midcontinent	7/1/2012 – 12/31/2012	$2.61/MMBtu – $3.23/MMBtu

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

As of December 31, 2011, we had invested a total of $13.8 million in the preferred stock of Faustina Hydrogen Products LLC, a company created to develop a proposed gasification plant from which CO2 would be produced as a byproduct and used by Denbury in its tertiary oil operations. The investment was recorded at cost, together with a $1.3 million receivable for accrued dividends receivable. The developer of the proposed plant was soliciting other potential investors for the project, and as of December 31, 2011, a third-party was actively engaged in due diligence. During 2012, a key investor and participant in the project announced its intent to abandon its investment in the proposed plant. As a result, due diligence by the potential third party investor ceased. Absent the key investor, we believe it is unlikely the plant will be constructed, and therefore, it is also unlikely our investment will generate future cash flows. Accordingly, we recorded a $15.1 million impairment charge for this investment during the first quarter of 2012, which is classified as “Impairment of assets” in the Unaudited Condensed Consolidated Statement of Operations for the six months ended June 30, 2012. The inputs used to determine fair value of the investment included the projected future cash flows of the plant and risk-adjusted rate of return that we estimated would be used by a market participant in valuing the asset. These inputs are unobservable within the marketplace and therefore considered Level 3 within the fair value hierarchy. However, as there are currently no expected future cash flows associated with the plant, the preferred stock was determined to have no value.

Other Fair Value Measurements

The carrying value of our Bank Credit Facility approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our senior subordinated notes as of June 30, 2012 and December 31, 2011 is $2,217.2 million and $2,253.2 million, respectively. The fair value hierarchy for long-term debt is primarily Level 1 (quoted prices for identical assets in active markets). We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 6. Commitments and Contingencies

We are involved in various lawsuits, claims and other regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated. We are also subject to audits for sales and use taxes and severance taxes in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe.

Note 7. Related Party

During the three and six months ended June 30, 2012, we purchased $4.0 million and $5.2 million, respectively of oil produced by a privately-held entity of which a member of our Board of Directors serves as chairman of the board. The oil purchased under this agreement is related to the non-core assets in central and southern Mississippi and in southern Louisiana (see further discussion in Note 2, Acquisitions and Divestitures) sold to this same entity in February 2012. The oil purchased under this agreement is part of a typical commercial transaction that would be entered into with a third party and is later blended with other oil and sold by Denbury to an unrelated third party. The purchase of oil is classified as “Marketing expenses” and the subsequent sale is included in “Interest income and other income” on the accompanying Unaudited Condensed Consolidated Statements of Operations. We are under no continuing obligation to purchase oil under this agreement.

In addition, during the first and second quarters of 2012, we entered into a sublease of a portion of our former corporate headquarters with the same privately-held entity. The sublease provides for payment of $2.5 million in lease rentals to us over the lease term, which expires on July 31, 2016. During the three and six months ended June 30, 2012, we recorded $172 thousand and $199 thousand, respectively, in lease income related to the new sublease arrangement, which is included in “Interest income and other income” in the Unaudited Condensed Consolidated Statements of Operations.

Note 8. Subsequent Event

During July 2012, we entered into an amendment to our Bank Credit Agreement (see Note 3, Long-Term Debt).

Management's Discussion and Analysis of Financial Condition and Results of Operations

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2011 (the "Form 10-K"), along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in the Form 10-K. Any terms used but not defined herein have the same meaning given to them in the Form 10-K. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with Risk Factors under Item 1A of Part II of this report, along with Forward-Looking Information at the end of this Item 2 for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are a growing independent oil and natural gas company. We are the largest combined oil and natural gas producer in both Mississippi and Montana, own the largest CO_2 reserves used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis on our CO_2 tertiary recovery operations.

Operating Highlights

We recognized net income of $211.9 million, or $0.55 per basic common share, during the second quarter of 2012 compared to net income of $259.2 million, or $0.65 per basic common share, during the second quarter of 2011. This decrease in net income between the two periods is primarily attributable to a $52.0 million ($32.3 million after-tax) smaller non-cash gain in the fair value of the Company's commodity derivative contracts in the most recent quarter than in the prior year's second quarter, and an increase in depletion, depreciation, and amortization of $28.8 million ($17.9 million after-tax).

During the second quarter of 2012, our oil and natural gas production, which was 93% oil, averaged 72,337 BOE/d compared to 64,919 BOE/d produced during the second quarter of 2011. This 11% increase in production is primarily attributable to increases in our Bakken and tertiary oil production, partially offset by normal declines in most of our other non-tertiary properties and a reduction from non-core properties sold in 2012 (see Sale of Non-Core Assets below). After adjusting quarterly production in both periods to exclude production from non-core properties which were sold in 2012, continuing production in the second quarter of 2012 increased 16% over production in the comparable prior year quarter and 4% sequentially over levels in the first quarter of 2012. Our tertiary oil production averaged 35,208 Bbls/d during the second quarter of 2012, an increase of 14% over the 30,771 Bbls/d produced during the second quarter of 2011 and 6% over first quarter 2012 levels. Our Bakken oil production averaged 15,208 BOE/d during the second quarter of 2012, which remained consistent with comparable first quarter 2012 production levels and an increase of 99% over Bakken production of 7,626 BOE/d during the second quarter of 2011. See Results of Operations — CO_2 Operations and Results of Operations — Operating Results — Production for more information.

Oil prices during the second quarter of 2012 were 9% lower than prices during the second quarter of 2011, with average NYMEX oil prices averaging $93.49 per Bbl in the second quarter of 2012, compared to average NYMEX prices of $102.58 per Bbl during the second quarter of 2011. Our average realized oil price received per barrel, excluding the impact of commodity derivative contracts, was $95.63 per Bbl during the second quarter of 2012, compared to $106.30 per Bbl during the second quarter of 2011, a 10% decrease between the comparative periods. In spite of the decrease in realized prices, the Company's oil and natural gas revenues increased slightly during the second quarter of 2012 compared to the same period in 2011. See Results of Operations – Operating Results – Oil and Natural Gas Revenues below for more information on our oil prices received and differentials to NYMEX prices.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Acquisition of Thompson Field

In June 2012, we acquired a nearly 100% working interest and 84.7% net revenue interest in Thompson Field for $366.2 million after preliminary closing adjustments. The field is located approximately 18 miles west of Denbury's Hastings Field which is currently being flooded with CO_2, and which is the current terminus of the Green Pipeline which transports CO_2 from Denbury's source in Jackson Dome, Mississippi. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is also expected to be an ideal candidate for a CO_2 flood. Under the terms of the agreement, after the initiation of CO_2 injection, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d. We funded the purchase principally with cash proceeds from property sales earlier this year and the remainder from borrowings under our revolving credit facility.

Sale of Non-Core Assets

On April 9, 2012, we completed the sale of certain non-operated assets in the Paradox Basin of Utah for $75.0 million. The sale had an effective date of January 1, 2012, and proceeds realized after final closing adjustments totaled $68.5 million. Closing adjustments included operating net revenues after January 1, 2012, net of capital expenditures, along with other purchase price adjustments.

On February 29, 2012, we completed the sale of certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $155.0 million. We realized net proceeds of $141.8 million, after final closing adjustments. The sale had an effective date of December 1, 2011 and consequently, operating revenues of $13.5 million after the effective date, net of capital and lease operating expenditures, along with any other purchase price adjustments, were adjustments to the selling price.

We structured the sale of our non-core assets and the purchase of Thompson Field as a like-kind exchange transaction for federal income tax purposes and anticipate deferral of a majority of the taxable gain recognized on the sale of the non-core assets. We did not record a gain or loss on either sale in accordance with the full cost method of accounting.

Sale of Investment in Vanguard Natural Resources LLC

On January 19, 2012, we sold our investment in Vanguard Natural Resources LLC ("Vanguard") common units for cash consideration of $83.5 million, net of related transaction fees. In connection with the sale, during the first quarter of 2012, we recorded a pretax $3.1 million loss which is classified as "Other expenses" in the Unaudited Condensed Consolidated Statements of Operations. The $3.1 million represents the difference between the net proceeds received from the sale and the carrying amount of the investment at December 31, 2011.

Addition of Proved Oil and Natural Gas Reserves

During the first six months of 2012, we added 85.3 MMBOE of estimated proved reserves, including tertiary oil reserves of 42.6 MMBbls at Hastings Field and 14.1 MMBbls at Oyster Bayou Field based on these fields' responses to CO_2 injections, 16.3 MMBOE due to further development in the Bakken, and 12.3 MMBOE of acquired reserves at Thompson Field. These increases were partially offset by the disposition of 12.7 MMBOE of reserves associated with the sale of non-core assets above.

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Management's Discussion and Analysis of Financial Condition and Results of Operations

Capital Resources and Liquidity

We currently project that our 2012 capital budget will be $1.5 billion, which excludes estimated equipment leases ($75 million), acquisitions, capitalized interest and start-up costs associated with our new tertiary floods. Our current 2012 capital budget includes the following:

- $430 million allocated for tertiary oil field expenditures;
- $480 million for development of our Bakken properties;
- $290 million for pipeline construction;
- $200 million to be spent on CO2 sources; and
- $100 million to be spent in all other areas.

Based on oil and natural gas prices in early August 2012 and our current production forecasts, we estimate that our 2012 capital budget (including capitalized interest and tertiary start-up costs) will be approximately $200 to $300 million greater than our 2012 anticipated cash flow from operations. We plan to fund any shortfall between our cash flow from operations and our capital spending with proceeds from our asset sales and borrowings under our bank credit facility.

During the first six months of 2012, we incurred capital expenditures of approximately $734.2 million, net of equipment lease recoveries of $33.1 million. Additionally, we have capitalized interest and tertiary start-up costs which are not included in the above mentioned amounts. See additional detail on our expenditures in the table below under Capital Expenditure Summary.

In October 2011, we commenced a share repurchase program for up to $500 million of Denbury common stock. To date we have repurchased $195.2 million of shares (all during the fourth quarter of 2011). Whether we make any share repurchases during the remainder of 2012 will be determined based on various parameters; therefore, it is uncertain whether or not we will make additional share repurchases of Denbury common stock under this program in the last half of 2012.

We continually monitor our capital spending and anticipated cash flows and believe that we can adjust our capital spending up or down depending on cash flows; however, any such reduction in capital spending could reduce our anticipated production levels in future years. We currently do not anticipate any material changes to our 2012 capital spending plans as a result of the recent decrease in oil prices, but we will attempt to match our 2013 capital spending with projected cash flow from operations. For 2012 and certain future years, we have contracted for certain capital expenditures; therefore, we cannot eliminate all of our capital commitments without penalties (refer to Management's Discussion and Analysis – Capital Resources and Liquidity – Off-Balance Sheet Arrangements — Commitments and Obligations in the Form 10-K). In addition to the potential flexibility in our capital spending plans, as of June 30, 2012, we had approximately $1.1 billion of unused availability under our bank credit facility and have oil price floors in place through 2013 (see Note 4, Derivative Instruments, to the Unaudited Condensed Consolidated Financial Statements), which together should provide us with adequate liquidity and flexibility to meet our near-term capital spending plans if oil prices were to remain at August 2012 levels or further decrease significantly. Also, we currently believe we could increase our borrowing base under our bank credit facility above the current $1.6 billion if we desired to do so.

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Management's Discussion and Analysis of Financial Condition and Results of Operations

Capital Expenditure Summary

The following table of capital expenditures includes accrued capital for the six months ended June 30, 2012 and 2011:

In thousands	Six Months Ended June 30, 2012	2011
Capital expenditures by project:		
Tertiary oil fields	$246,633	$245,061
Bakken	234,970	173,067
CO2 pipelines	83,115	51,444
CO2 sources (1)	132,096	46,684
Other areas	70,565	86,457
Capital expenditures before acquisitions and capitalized interest	767,379	602,713
Less: recoveries from sale/leaseback transactions	(33,131)	(25,571)
Net capital expenditures excluding acquisitions and capitalized interest	734,248	577,142
Acquisitions:		
Property acquisitions (2)	367,929	32,482
Capitalized interest	37,920	24,151
Capital expenditures, net of sale/leaseback transactions	$1,140,097	$633,775

(1) Includes capital expenditures related to the Riley Ridge gas plant.

(2) Includes capital expenditures of $212.5 million that are not reflected as an Investing Activity on our Unaudited Condensed Consolidated Statements of Cash Flows due to the movement of proceeds through a qualified intermediary. See Note 2, Acquisitions and Divestitures to the Unaudited Condensed Consolidated Financial Statements.

Our capital expenditures for the first six months of 2012 were funded with $732.6 million of cash flow from operations, $210.3 million of net proceeds (after final closing adjustments) from non-core oil and natural gas asset divestitures, $83.5 million of proceeds from the sale of our investment in Vanguard common units and the remainder with borrowings under our bank credit facility. Our capital expenditures for the first six months of 2011 were funded with $523.4 million of cash flow from operations and the remainder with cash on hand at the beginning of the period.

Off-Balance Sheet Arrangements

Our obligations that are not currently recorded on our balance sheet consist of various obligations for development and exploratory expenditures arising from purchase agreements, our capital expenditure program, or other transactions common to our industry. In addition, in order to recover our proved undeveloped reserves, we must also fund the associated future development costs as forecasted in our proved reserve reports. Our derivative contracts, which are recorded at fair value in our balance sheets, are discussed in Notes 4 and 5 to the Unaudited Condensed Consolidated Financial Statements.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Our commitments and obligations consist of those detailed as of December 31, 2011 in the Form 10-K, subject to the correction in the classification of our equipment leases from operating to capital (see Note 3, Long-Term Debt), under Management's Discussion and Analysis of Financial Condition and Results of Operations – Off-Balance Sheet Arrangements – Commitments and Obligations.

Results of Operations

CO2 Operations

Our focus on CO2 operations is the primary strategy of our business and operations. We believe there are significant additional oil reserves and production that can be obtained through the use of CO2, and we have outlined certain of this estimated potential in our Form 10-K and other public disclosures. In addition to its long-term effect, our focus on these types of operations impacts certain trends in our current and near-term operating results. Please refer to Management's Discussion and Analysis of Financial Condition and Results of Operations and the section entitled CO2 Operations contained in our Form 10-K for further information regarding these matters.

During the second quarter of 2012, our CO2 production at Jackson Dome averaged 915 MMcf/d, compared to an average of 992 MMcf/d produced during the second quarter of 2011 and 1,047 MMcf/d produced during the first quarter of 2012. We used 90% of this production, or 828 MMcf/d, in our tertiary operations during the second quarter of 2012, and sold the balance to our industrial customers or to Genesis Energy, L.P. pursuant to our volumetric production payment contracts. Refer to Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Off-Balance Sheet Arrangements – Commitments and Obligations in our Form 10-K for further discussion of our CO2 delivery obligations. The reduction in CO2 production during the second quarter of 2012 compared to the prior quarter is a result of lower demand for CO2 at our tertiary oil fields as part of our ongoing process to maximize the utilization of CO2; however we expect the production volume to fluctuate depending on the various stages of tertiary field development. With the acquisition of Thompson Field in 2012, we will likely need to develop some of our probable and possible CO2 reserves at Jackson Dome so that we have sufficient proved reserves to flood this newly acquired field. We anticipate an ongoing exploration and development program at Jackson Dome designed to increase both the CO2 production rate and proved reserves that will be available to us until substantial anthropogenic sources are developed, which is currently expected to first occur several years in the future. At December 31, 2011, our proven CO2 reserves at Jackson Dome were approximately 6.7 Tcf on a gross working interest basis, of which Denbury's net revenue interest was approximately 5.3 Tcf, and include reserves dedicated to volumetric production payments of 84.7 Bcf.

We spent approximately $0.28 per Mcf to produce and pay royalties and taxes for the CO2 we utilize in our tertiary floods during the first six months of 2012, including $0.28 per Mcf during the first quarter of 2012 and $0.29 per Mcf during the second quarter of 2012. These rates have remained relatively consistent with the $0.27 per Mcf spent during the first six months of 2011 and $0.28 per Mcf cost during the second quarter of 2011. Our estimated cost of CO2, after inclusion of depreciation and amortization expense related to the CO2 production but excluding depreciation of our CO2 pipelines was $0.36 per Mcf and $0.35 per Mcf during the three and six months ended June 30, 2012, respectively, compared to $0.33 per Mcf and $0.32 per Mcf during the same periods in 2011.

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following table summarizes our tertiary oil production and tertiary lease operating expense per barrel for each quarter in 2011 and the first and second quarters of 2012:

	Average Daily Production (Bbls/d)					
Tertiary Oil Field	First Quarter 2011	Second Quarter 2011	Third Quarter 2011	Fourth Quarter 2011	First Quarter 2012	Second Quarter 2012
Phase 1:						
Brookhaven	3,664	3,213	3,030	3,121	3,014	2,779
McComb area	2,161	1,983	2,005	1,843	1,746	1,902
Mallalieu area	2,925	2,646	2,620	2,587	2,585	2,461
Other	3,290	3,196	2,879	2,749	2,500	2,444
Phase 2:						
Heidelberg	3,374	3,548	3,141	3,728	3,583	3,823
Eucutta	3,247	3,114	2,985	3,139	3,090	2,870
Soso	2,582	2,317	2,331	2,162	2,063	1,947
Martinville	500	416	453	481	551	480
Phase 3:						
Tinsley	6,567	6,990	7,075	6,338	7,297	8,168
Phase 4:						
Cranfield	991	1,085	1,214	1,200	1,152	1,094
Phase 5:						
Delhi	1,524	2,263	3,358	3,778	4,181	4,023
Phase 7:(1)						
Hastings	—	—	—	—	618	1,913
Phase 8:						
Oyster Bayou	—	—	—	18	877	1,304
Total tertiary oil production (Bbl/d)	30,825	30,771	31,091	31,144	33,257	35,208
Tertiary lease operating expense per Bbl	$ 24.93	$ 22.87	$ 24.91	$ 23.59	$ 26.74	$ 22.95

(1) As of June 30, 2012, we did not have any tertiary production from our fields in Phase 6, Citronelle Field, which will require an extension to the Free State CO2 Pipeline or another pipeline, depending on the ultimate CO2 source for this field, the timing of which is uncertain.

Oil production from our tertiary operations increased to an average of 35,208 Bbls/d during the second quarter of 2012, a 14% increase over our second quarter 2011 tertiary production levels, primarily due to production growth in response to continued expansion of the tertiary floods in Heidelberg, Tinsley and Delhi fields and production at our Oyster Bayou and Hastings CO2 fields, which experienced their initial tertiary production response in late December 2011 and early January 2012, respectively. Offsetting second quarter production gains were declines in our more mature Phase 1 and Phase 2 fields (except Heidelberg). Production during the second quarter of 2012 increased 1,951 Bbls/d compared to first quarter 2012 levels primarily due to production growth in response to continued expansion of the tertiary floods in the Heidelberg and Tinsley fields and increased production response of the tertiary floods at our Oyster Bayou and Hastings fields. Offsetting these production gains were declines in our more mature Phase 1 and Phase 2 fields (except McComb and Heidelberg).

The production growth rate at a tertiary flood can vary from quarter to quarter as a tertiary field's production may increase rapidly when wells respond to the CO_2, plateau temporarily, and then resume its growth as additional areas of the field are developed. During a tertiary flood life cycle, facility capacity is increased from time to time, which occasionally requires temporary shutdowns during installation, thereby causing temporary declines in production. We also find it difficult to precisely predict when any given well will respond to the injected CO_2, as the CO_2 seldom travels through the rock consistently due to heterogeneity in the oil-bearing formations. We find all of these fluctuations to be normal, and generally expect oil production at a tertiary field to increase over time until the entire field is developed, albeit sometimes in inconsistent patterns. At Heidelberg Field, during the second half of 2011 and the first half of 2012, we modified 39 wells and 31 wells, respectively, in order to address conformance issues (i.e., to control the flow of the CO_2 to the desired geologic zone within the reservoir). We continue to see improvement in the gas/oil ratio and production in West Heidelberg, an indication that the conformance is working and that we are contacting the oil with CO_2. At Tinsley Field, during the third quarter of 2011, we stopped CO_2 injections in parts of the field in order to address issues with wells that were improperly plugged by prior operators. Full CO_2 injections resumed during the first quarter of 2012 in Tinsley Field, which responded with an increase in sequential production in the first and second quarter of 2012 of 15% and 12%, respectively.

During the second quarter of 2012, operating costs for our tertiary properties averaged $22.95 per Bbl, compared to $22.87 per Bbl during the second quarter of 2011 as increases in tertiary operating expense due to our new tertiary floods at Oyster Bayou and Hastings fields were partially offset by a decrease in tertiary operating expense due to the change in classification of our equipment leases from operating to capital in the current quarter. Higher lease operating expenses per barrel at Hastings and Oyster Bayou Fields are typical of a new tertiary flood because of the relatively low production in the early stages of the flood. For any specific field, we expect our tertiary lease operating expense per barrel to be high initially and then decrease as production increases, ultimately leveling off until production begins to decline in the later life of the field, when lease operating expense per barrel will again increase.

Management’s Discussion and Analysis of Financial Condition and Results of Operations

Operating Results

Certain of our operating results and statistics for the comparative second quarters and first six months of 2012 and 2011 are included in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share and unit data	2012	2011	2012	2011
Operating results				
Net income	$ 211,865	$ 259,246	$ 325,332	$ 245,056
Net income per common share – basic	0.55	0.65	0.84	0.62
Net income per common share – diluted	0.54	0.64	0.83	0.61
Net cash provided by operating activities	440,966	398,521	732,620	523,353
Average daily production volumes				
Bbls/d	67,476	59,538	67,167	59,002
Mcf/d	29,163	32,283	28,608	31,579
BOE/d(1)	72,337	64,919	71,934	64,265
Operating revenues				
Oil sales	$ 587,191	$ 575,928	$ 1,210,897	$ 1,068,766
Natural gas sales	4,950	15,171	14,745	28,525
Total oil and natural gas sales	$ 592,141	$ 591,099	$ 1,225,642	$ 1,097,291
Commodity derivative contracts(2)				
Cash receipt (payment) on settlement of commodity derivative contracts	$ 7,282	$ (10,942)	$ 6,092	$ (9,354)
Non-cash fair value adjustment income	131,827	183,846	87,742	11,508
Total income from commodity derivative contracts	$ 139,109	$ 172,904	$ 93,834	$ 2,154
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$ 95.63	$ 106.30	$ 99.06	$ 100.08
Natural gas price per Mcf	1.87	5.16	2.83	4.99
Unit prices – including impact of derivative settlements(2)				
Oil price per Bbl	$ 95.51	$ 103.17	$ 98.33	$ 98.02
Natural gas price per Mcf	4.88	7.22	5.72	7.20
Oil and natural gas operating expenses				
Lease operating expenses	$ 124,511	$ 126,085	$ 262,475	$ 249,882
Marketing expenses	12,218	6,270	23,048	11,573
Taxes other than income(3)	38,812	39,632	82,506	72,115
Oil and natural gas operating revenues and expenses per BOE(1)				
Oil and natural gas revenues	$ 89.96	$ 100.06	$ 93.62	$ 94.33
Lease operating expenses	18.92	21.34	20.05	21.48
Marketing expenses, net of third party purchases	1.26	1.06	1.46	0.99
Taxes other than income	5.90	6.71	6.30	6.20

Non-tertiary CO2 revenues and expenses:				
CO2 sales and transportation fees	$ 5,301	$ 5,343	$ 12,096	$ 10,267
CO2 discovery and operating expenses(4)	(1,062)	(1,693)	(7,267)	(3,639)
CO2 revenue and expenses, net	$ 4,239	$ 3,650	$ 4,829	$ 6,628

(1) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas ("BOE").

(2) See also Item 3. Quantitative and Qualitative Disclosures about Market Risk below for information concerning the Company's derivative transactions.

(3) Includes ad valorem, production and franchise taxes.

(4) Includes $4.8 million of exploratory drilling costs during the six months ended June 30, 2012. We incurred no exploratory drilling costs during the three months ended June 30, 2012 nor the three and six months ended June 30, 2011.

Production

Average daily production by area for each of the four quarters of 2011 and for the first and second quarters of 2012 is shown below:

	Average Daily Production (BOE/d)					
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter
Operating Area	2011	2011	2011	2011	2012	2012
Gulf Coast region:						
Tertiary oil fields	30,825	30,771	31,091	31,144	33,257	35,208
Non-tertiary fields:						
Mississippi	5,930	5,642	5,636	4,746	4,573	4,095
Texas	4,371	4,202	4,096	3,868	3,674	4,573
Louisiana	511	454	47	141	191	189
Alabama and other	1,020	1,079	1,064	1,031	1,090	1,117
Total Gulf Coast region	42,657	42,148	41,934	40,930	42,785	45,182
Rocky Mountain region:						
Cedar Creek Anticline	9,163	8,925	8,930	8,858	8,496	8,535
Bakken	5,728	7,626	9,976	11,743	15,114	15,208
Bell Creek	890	936	889	840	859	816
Other	2,613	2,693	2,689	2,533	2,516	2,539
Total Rocky Mountain region	18,394	20,180	22,484	23,974	26,985	27,098
Total Continuing Production	61,051	62,328	64,418	64,904	69,770	72,280
Properties disposed:						
Gulf Coast assets(1)	1,918	1,901	1,732	1,677	1,054	—
Paradox assets(2)	635	690	680	653	708	57
Total Production	63,604	64,919	66,830	67,234	71,532	72,337

(1) Includes production from certain non-core Gulf Coast assets sold in late February 2012.
(2)

Includes production from certain non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012.

Continuing production during the three months ended June 30, 2012 increased 16% or 9,952 BOE/d over 2011 comparable period continuing production levels, and continuing production increased from 61,693 BOE/d during the first six months of 2011 to 71,025 BOE/d during the first six months of 2012 (a 15% increase). These increases were primarily due to production increases from the Bakken and our tertiary oil fields (see a discussion of our tertiary operations in CO2 Operations above), offset by normal declines in most of our other non-tertiary properties. Total production increased 11% between the second quarters of 2011 and 2012, and includes production related to certain non-core Gulf Coast assets sold in February 2012 and non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012. On a year-to-date basis, total production increased 12% between the first six months of 2011 and 2012.

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Production from our Bakken properties averaged 15,208 BOE/d in the second quarter of 2012, which increased slightly from first quarter 2012 production levels and increased 99% from second quarter 2011 levels. The production increases in the Bakken are due to the acceleration of our drilling activities in the area in 2011. During 2011, we operated as many as seven drilling rigs in the Bakken, decreasing to six operated drilling rigs by the end of 2011. We have currently reduced the rig count in the Bakken to four, which has begun to slow the rate of Bakken production growth. During the first six months of 2012, we completed 22 operated wells in the Bakken which had initial production during the period.

Although our production from the Cedar Creek Anticline is generally declining, due to a third party's net profits interest Cedar Creek Anticline production increased in the second quarter of 2012 compared to production during the first quarter of 2012, as lower oil prices result in a lower net profits interest and thus in our realizing higher production quantities.

Our production during both the three and six months ended June 30, 2012 was 93% oil, which remained consistent with oil production of 92% during the three and six months ended June 30, 2011.

Oil and Natural Gas Revenues. Our oil and natural gas revenues remained flat during the three months ended June 30, 2012 compared to the same period in 2011, and increased 12% between the comparative six month periods. The increase during the most recent six month period is related to increases in production, offset by reductions in commodity prices. Changes in oil and natural gas revenues, excluding any impact of our commodity derivative contracts, are reflected in the following table:

	Three Months Ended June 30, 2012 vs. 2011		Six Months Ended June 30, 2012 vs. 2011	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Increase in production	$ 67,541	11%	$ 137,736	13%
Decrease in commodity prices	(66,499)	-11%	(9,385)	-1%
Total increase in oil and natural gas revenues	$ 1,042	0%	$ 128,351	12%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first and second quarters and the six months ended June 30, 2012 and 2011:

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net Realized Prices:						
Oil price per Bbl	$102.52	$93.67	$95.63	$106.30	$99.06	$100.08
Natural gas price per Mcf	3.84	4.81	1.87	5.16	2.83	4.99
Price per BOE	97.32	88.42	89.96	100.06	93.62	94.33

NYMEX Differentials:						
Oil per Bbl	$(0.37)	$(0.59)	$2.14	$3.72	$0.87	$1.64
Natural gas per Mcf	1.32	0.61	(0.49)	0.78	0.40	0.70

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As reflected in the table above, our net realized oil prices decreased in the second quarter of 2012 compared to those received during the second quarter of 2011, while oil differentials also declined between the two periods. Company-wide oil price differentials in the second quarter of 2012 were $2.14 per Bbl above NYMEX, compared to an average differential of $3.72 per Bbl above NYMEX in the second quarter of 2011 and $0.37 per Bbl below NYMEX in the first quarter of 2012. Our favorable NYMEX differentials during the three and six months ended June 30, 2012 and 2011 are primarily due to the favorable differential for crude oil sold under Light Louisiana Sweet ("LLS") index prices. Prices received in a regional market can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors and location differentials. NYMEX pricing, which has long been a benchmark price that reflects the economics in the U.S. midcontinent market, has been influenced in the recent past by significant increases in supply. Alternatively, the LLS market is reflective of market economics in the Gulf Coast region, where both foreign and domestic oil is bought and sold, and correlates more closely to global oil prices. During the second quarter of 2012, the Company sold approximately 40% of its crude oil at prices based on the LLS index price, approximately 20% at prices tied to a combination of the LLS index price and other indexes, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region. This LLS-to-NYMEX differential averaged a positive $18.14 per Bbl on a trade-month basis for the second quarter of 2012, compared to a positive $15.32 per Bbl differential in the second quarter of 2011 and a positive $12.55 per Bbl differential in the first quarter of 2012. While this differential is significant in the pricing for our oil production, other factors may prevent us from realizing the full differential. As indicated by the above variations, the LLS-to-NYMEX differential is volatile and has been at historically high levels in recent periods, which may not continue. The differential for oil production sold in the Bakken averaged $20.16 per Bbl below NYMEX in the second quarter of 2012, compared to an average differential of $9.62 per Bbl below NYMEX in the second quarter of 2011 and $16.96 per Bbl below NYMEX in the first quarter of 2012. Oil in the Bakken region sold at a significant discount during the first and second quarter of 2012 due to increased production in the area coupled with limited transportation infrastructure.

Commodity Derivative Contracts. The following tables summarize the impact our commodity derivative contracts had on our operating results for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,					
	2012	2011	2012	2011	2012	2011
In thousands	Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Non-cash fair value gain (loss)	$140,923	$187,194	$(9,096)	$(3,348)	$131,827	$183,846
Cash settlement receipts (payments)	(709)	(16,972)	7,991	6,030	7,282	(10,942)
Total	$140,214	$170,222	$(1,105)	$2,682	$139,109	$172,904

	Six Months Ended June 30,					
	2012	2011	2012	2011	2012	2011
In thousands	Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Non-cash fair value gain (loss)	$ 98,478	$ 20,130	$ (10,736)	$ (8,622)	$ 87,742	$ 11,508
Cash settlement receipts (payments)	(8,939)	(22,000)	15,031	12,646	6,092	(9,354)
Total	$ 89,539	$ (1,870)	$ 4,295	$ 4,024	$ 93,834	$ 2,154

Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our commodity derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the changes in fair value of these contracts, as outlined above, are recognized currently in the income statement. See Notes 4 and 5 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

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Production Expenses. Lease operating expenses during the three months ended June 30, 2012 of $124.5 million decreased $1.6 million (1%) compared to lease operating expenses in the same period in 2011, which change consisted of a 15% increase in operating expense of our tertiary oil properties offset by an 18% decrease in non-tertiary operating expense. Lease operating expense during the six months ended June 30, 2012 of $262.5 million increased $12.6 million (5%) compared to lease operating expenses in the same period in 2011, consisting of a 16% increase in our tertiary operating expense offset by a 7% decrease in non-tertiary operating expense. See discussion of tertiary operating expenses above under CO2 Operations. The decrease in non-tertiary operating expense during both comparable periods is primarily due to the divestiture of certain non-core assets located in central and southern Mississippi, southern Louisiana, and in the Paradox Basin of Utah during the first and second quarters of 2012.

Lease operating expense averaged $18.92 and $20.05 per BOE for the three and six months ended June 30, 2012, a decrease of 11% and 7% compared to $21.34 and $21.48 per BOE, respectively, for the same periods in 2011. The lower operating expenses per BOE during both comparative periods were driven by our non-tertiary properties and are primarily due to increased Bakken production, which has lower operating costs than our other properties, and the sale of certain non-core assets during the first half of 2012, which had a higher operating cost per BOE compared to the average of our other properties. Our tertiary operating costs, which have historically been higher than our Company-wide operating costs, averaged $22.95 and $24.79 per Bbl during the three and six months ended June 30, 2012, respectively, compared to $22.87 and $23.90 per Bbl for the same periods in 2011, which increase is primarily driven by the initiation of two new tertiary floods in early 2012. See CO2 Operations for a more detailed discussion of our tertiary operating costs.

Taxes other than income, which includes ad valorem, production and franchise taxes, averaged $5.90 and $6.30 per BOE for the three and six months ended June 30, 2012, compared to $6.71 and $6.20 per BOE for the same periods in 2011. The decrease between the three month periods is largely attributable to a decrease in production taxes based on favorable tax rates for qualifying properties, with a corresponding increase in production.

General and Administrative Expenses ("G&A")

In thousands, except per BOE data and employees	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Administrative costs	$71,739	$ 59,615	$ 145,798	$ 126,943
Stock-based compensation	9,364	9,687	19,958	21,024
Operator labor and overhead recovery charges	(34,382)	(31,423)	(70,006)	(60,692)
Capitalized exploration and development costs	(11,895)	(9,170)	(24,317)	(16,247)
Net G&A expense	$34,826	$ 28,709	$ 71,433	$ 71,028
G&A per BOE:				
Administrative costs, net	$4.27	$ 3.64	$ 4.41	$ 4.70
Stock-based compensation, net	1.02	1.22	1.05	1.41
Net G&A expense	$5.29	$ 4.86	$ 5.46	$ 6.11
Employees as of June 30	1,414	1,283	1,414	1,283

Net G&A expense during the three months ended June 30, 2012 increased on both an absolute dollar and per BOE basis compared to levels in the second quarter of 2011, as the increases in administrative costs exceeded the increase in operator labor and overhead recovery charges and capitalized exploration and developments costs. Net G&A expense during the six months ended June 30, 2012 increased slightly on an absolute dollar basis, but decreased on a per BOE basis compared to levels in the same period in 2011, as higher administrative costs were offset by increases in operator labor and overhead recovery charges and capitalized exploration and development costs. The 9% increase and 11% decrease in G&A per BOE between the two periods was further impacted by higher production.

Administrative costs increased $12.1 million (20%) and $18.9 million (15%) during the three and six months ended June 30, 2012, respectively, compared to the same periods in 2011. The increase between the comparative three and six month periods was primarily due to an increase in compensation-related costs due to an increase in headcount (10%) and salaries, which we consider necessary to remain competitive in our industry, as well as increases in our employee-related insurance costs.

Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of additional operated wells and drilling activities, additional tertiary operations and increased compensation expense, the amount we recovered as operator labor and overhead charges increased by 9% and 15% during the three and six months ended June 30, 2012, respectively, compared to the same periods in 2011. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

Interest and Financing Expenses

In thousands, except per BOE data and interest rates	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Cash interest expense	$ 56,376	$ 50,509	$ 108,409	$ 104,715
Non-cash interest expense	3,703	4,934	7,429	10,462
Less: capitalized interest	(18,475)	(13,194)	(37,920)	(24,151)
Interest expense	$ 41,604	$ 42,249	$ 77,918	$ 91,026
Interest income and other income	$ 4,339	$ 4,955	$ 9,159	$ 8,004
Net cash interest expense and other income per BOE (1)	$ 5.10	$ 5.54	$ 4.69	$ 6.31
Average debt outstanding	$ 2,964,121	$ 2,305,104	$ 2,854,523	$ 2,409,284
Average interest rate (2)	7.6%	8.8%	7.6%	8.7%

(1) Cash interest expense less capitalized interest less interest and other income on BOE basis.
(2) Includes commitment fees but excludes debt issue costs and amortization of discount and premium.

Cash interest expense increased $5.9 million (12%) and $3.7 million (4%) during the three and six months ended June 30, 2012, respectively, compared to the same periods in 2011, primarily due to an increase in the average debt outstanding, offset slightly by a reduction in the average interest rate. The reduction in the average interest rate is primarily a result of increased borrowings under our bank credit facility, which carries rates lower than that of our senior subordinated notes. The increase in capitalized interest between the three and six months ended June 30, 2011 and 2012 relates primarily to incremental capitalized interest on CO_2 floods under development and the Riley Ridge plant and Greencore pipeline construction projects.

Denbury Resources Inc.

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Depletion, Depreciation, and Amortization ("DD&A")

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per BOE data	2012	2011	2012	2011
Depletion and depreciation of oil and natural gas properties	$ 109,279	$ 91,961	$ 216,334	$ 174,047
Depletion and depreciation of CO2 properties	5,427	4,588	10,537	9,178
Asset retirement obligations	1,829	1,696	3,524	3,259
Depreciation of other fixed assets	15,754	5,250	22,789	10,605
Total DD&A	$ 132,289	$ 103,495	$ 253,184	$ 197,089
DD&A per BOE:				
Oil and natural gas properties	$ 16.88	$ 15.85	$ 16.79	$ 15.24
CO2 and other fixed assets	3.22	1.67	2.55	1.70
Total DD&A cost per BOE	$ 20.10	$ 17.52	$ 19.34	$ 16.94

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs. As such, our DD&A rate has changed significantly over time, and it may continue to change in the future. During the second quarter of 2012, we added estimated proved reserves of 42.6 MMBOE at Hastings Field, 12.0 MMBOE in the Bakken and 12.3 MMBOE associated with our acquisition of Thompson Field. These additions were offset by a 6.1 MMBOE reduction in estimated proved reserves due to the sale of our non-core assets in the Paradox Basin. In conjunction with the recognition of proved reserves at Hastings Field, we transferred $222.5 million from Unevaluated Properties to Proved properties on our Unaudited Condensed Consolidated Balance Sheet. On a sequential quarterly basis, these changes to estimated proved reserves did not have a significant impact on our overall DD&A rate per BOE since the addition of the lower cost tertiary reserves were offset by other higher cost reserve additions.

Depletion of oil and natural gas properties increased 19% and 24% on an absolute-dollar basis for the three and six months ended June 30, 2012, respectively, and 6% and 10% on a per-BOE basis during the three and six months ended June 30, 2012, respectively, compared to the same periods in 2011, primarily due to higher finding costs per barrel and upward revisions in estimated future development costs associated with the Bakken capital program. The increase in DD&A on an absolute-dollar basis was further impacted by increases in production volumes.

The increase in depreciation of other fixed assets is primarily due to incremental pipeline depreciation and the change in classification of our equipment leases from operating to capital during the second quarter of 2012.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have a ceiling test write-down at June 30, 2012; however, if oil and natural gas prices were to decrease significantly in subsequent periods, we may be required to record write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict, and will depend, in part, upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures, as well as additional capital spent.

Impairment of Assets

We recognized $17.5 million of impairment charges during the six months ended June 30, 2012, primarily related to our investment in Faustina Hydrogen Products LLC, an entity created to develop a proposed plant from which we would offtake CO2. See Note 5, Fair Value Measurements, to the Unaudited Condensed Consolidated Financial Statements.

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Income Taxes

In thousands, except per BOE amounts and tax rates	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Current income tax expense	$ 784	$ 12,028	$ 29,492	$ 11,180
Deferred income tax expense	130,152	152,528	167,289	144,620
Total income tax expense	$ 130,936	$ 164,556	$ 196,781	$ 155,800
Average income tax expense per BOE	$ 19.89	$ 27.85	$ 15.03	$ 13.39
Effective tax rate	38.2 %	38.8 %	37.7 %	38.9 %

Our income taxes are based on an estimated statutory rate of approximately 38%. Our effective tax rate for the second quarters of 2012 and 2011, and the six months ended June 30, 2011, were slightly higher than our statutory rate, primarily due to nondeductible expenses. During the six months ended June 30, 2012, our effective tax rate was slightly lower than our statutory rate primarily due to the sale of our Vanguard common units in January 2012, which allowed us to utilize a larger amount of preferential tax benefits due to the higher taxable income from the sale, offset in part by nondeductible expenses. The amount recorded as current income tax expense represents our federal alternative minimum taxes that we cannot offset with enhanced oil recovery credits and our state income taxes during the three and six months ended June 30, 2012 and 2011.

As of June 30, 2012, we had an estimated $53.4 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2012 or future years, but cannot be used to offset alternative minimum tax. The enhanced oil recovery credits do not begin to expire until 2023. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we do not currently expect to earn additional enhanced oil recovery credits unless oil prices were to significantly deteriorate.

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Per BOE Data

The following table summarizes our cash flow, DD&A, and results of operations on a per BOE basis for the comparative periods. Each of the individual components is discussed above.

	Three Months Ended June 30,		Six Months Ended June 30,	
Per BOE data	2012	2011	2012	2011
Oil and natural gas revenues	$ 89.96	$ 100.06	$ 93.62	$ 94.33
Gain (loss) on settlements of derivative contracts	1.10	(1.85)	0.47	(0.80)
Lease operating expenses	(18.92)	(21.34)	(20.05)	(21.48)
Marketing expenses, net of third party purchases	(1.26)	(1.06)	(1.46)	(0.99)
Production netback	70.88	75.81	72.58	71.06
CO2 sales, net of operating expenses	0.65	0.62	0.36	0.57
Taxes other than income(1)	(5.90)	(6.71)	(6.30)	(6.20)
General and administrative expenses	(5.29)	(4.86)	(5.46)	(6.11)
Net cash interest expense and other income	(5.10)	(5.54)	(4.69)	(6.31)
Other	(0.27)	(1.08)	(1.96)	(0.12)
Changes in assets and liabilities relating to operations	12.02	9.22	1.42	(7.90)
Cash flow from operations	66.99	67.46	55.95	44.99
DD&A	(20.10)	(17.52)	(19.34)	(16.94)
Deferred income taxes	(19.77)	(25.82)	(12.78)	(12.43)
Loss on early extinguishment of debt	—	(0.06)	—	(1.39)
Non-cash commodity derivative adjustments	20.03	31.12	6.70	0.99
Impairment of assets	(0.03)	—	(1.34)	—
Other non-cash items	(14.93)	(11.30)	(4.34)	5.85
Net income	$ 32.19	$ 43.88	$ 24.85	$ 21.07

(1) "Taxes other than income" includes production taxes related to oil and natural gas production of $4.71 and $5.11 for the three and six months ended June 30, 2012, respectively, and $5.70 and $5.27 for the three and six months ended June 30, 2011, respectively.

Critical Accounting Policies

For additional discussion of our critical accounting policies, which remain unchanged, see Management's Discussion and Analysis of Financial Condition and Results of Operations in the Form 10-K.

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Management's Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Information

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in the section "Management's Discussion and Analysis of Financial Condition and Results of Operations", are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted cash flows and capital expenditures, drilling activity or methods including the timing and location thereof, acquisition or disposition plans and proposals, development activities, timing of CO2 injections and initial production responses thereto, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO2 reserves, helium reserves, potential reserves, percentages of recoverable original oil in place, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and gas prices, cost and availability of equipment and services, liquidity, availability of capital, borrowing capacity, regulatory matters, prospective legislation affecting the oil and gas industry, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics and other variables surrounding our operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "anticipate," "projected," "should," "assume," "believe," "may," or other words that convey, or are intended to convey uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil and/or natural gas prices and consequently in the prices received or demand for the Company's oil and natural gas; levels of future capital expenditures; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results; operating hazards; disruption of operations and damages from hurricanes, tropical storms, or forest fires; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial and credit markets; general economic conditions; competition; government regulations, including tax and environmental; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this quarterly report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company's other public reports, filings and public statements including, without limitation, the Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Long-term Debt and Interest Rate Sensitivity

We finance some of our acquisitions and other expenditures with fixed and variable-rate debt. Our bank credit agreement and our senior subordinated notes do not have any triggers or covenants regarding our debt ratings with rating agencies. Borrowings on our bank credit facility, which bear interest at variable rates, expose us to market risk related to changes in interest rates. As of June 30, 2012, our borrowings on our bank credit facility were $520.0 million, with a weighted average interest rate of 2.0%. At this level of variable-rate debt, an increase or decrease of 10% in interest rates would have an immaterial effect on our interest expense.

The following table presents the principal balances of our debt, by maturity date, as of June 30, 2012:

In thousands, except percentages	2014	2015	2016	2017	2020	2021
Variable rate debt:						
Bank Credit Facility (weighted average interest rate of 2.00% at June 30, 2012)	$ —	$ —	$ 520,000	$ —	$ —	$ —
Fixed rate debt:						
9½% Senior Subordinated Notes due 2016	—	—	224,920	—	—	—
9¾% Senior Subordinated Notes due 2016	—	—	426,350	—	—	—
8¼% Senior Subordinated Notes due 2020	—	—	—	—	996,273	—
6 % Senior Subordinated Notes due 2021	—	—	—	—	—	400,000
Other Subordinated Notes	1,072	485	—	2,250	—	—

Commodity Derivative Contracts and Commodity Price Sensitivity

From time to time, we enter into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year, depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production approximately 12 to 18 months in the future from the current quarter, as we believe it is important to protect our future cash flow for a short period of time in order to give us time to adjust to commodity price fluctuations, particularly since many of our expenditures have long lead times. See Notes 4 and 5 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. We only enter into commodity derivative contracts with parties that are lenders under our bank credit agreement. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to our commodity derivative contracts. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

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At June 30, 2012, our commodity derivative contracts were recorded at their fair value, which was a net asset of approximately $93.9 million (excluding $1.2 million of deferred premiums that we are obligated to pay for our derivative contracts, which payments are not subject to changes in commodity prices), a change of approximately $87.8 million from the $6.1 million fair value net asset recorded at December 31, 2011 (excluding $4.1 million of deferred premiums). This change is primarily related to changes in oil futures prices between December 31, 2011 and June 30, 2012.

Based on NYMEX crude oil and natural gas futures prices as of June 30, 2012, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as seen in the following table:

	Receipt / (Payment)	
In thousands	Crude Oil Derivative Contracts	Natural Gas Derivative Contracts
Based on:		
NYMEX futures prices as of June 30, 2012	$(572)	$13,359
10% increase in prices	(1,561)	12,292
10% decrease in prices	27,132	14,432

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) was performed under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the Company’s Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of June 30, 2012, to ensure that information required to be disclosed in the reports the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company’s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Evaluation of Changes in Internal Control over Financial Reporting. Under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer, the Company determined that, during the second quarter of fiscal 2012, there were no changes in its internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information with respect to legal proceedings is incorporated by reference from the Form 10-K.

Item 1A. Risk Factors

Information with respect to the risk factors has been incorporated by reference from Item 1A of the Form 10-K. There have been no material changes to the risk factors since the filing of the Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the second quarter of 2012, made solely in connection with delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted shares and the exercise of stock appreciation rights:

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
April 2012	17,737	$ 18.36	—	$ —
May 2012	8,871	18.21	—	—
June 2012	14,553	14.88	—	—
Total	41,161	17.10	—	$ —

During the three and six months ended June 30, 2012, the Company made no repurchases of common stock under its share repurchase program that began in October 2011. See Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity for more information.

Item 3. Defaults upon Senior Securities

None

Item 4. Mine Safety Disclosures

None

Item 5. Other Information

None

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Item 6. Exhibits

Exhibit	Description
3(a)	Certificate of Amendment of Restated Certificate of Incorporation of Denbury Resources Inc. (incorporated by reference as Exhibit 3.1 of our Form 8-K filed on May 21, 2012).
3(b)	Amended and Restated Bylaws of Denbury Resources Inc. (incorporated by reference as Exhibit 3.2 of our Form 8-K filed on May 21, 2012).
4(a)*	Eighth Amendment to Credit Agreement dated as of March 9, 2010, dated as of July 26, 2012, among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files.

* Filed herewith.

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SIGNATURES

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

DENBURY RESOURCES INC.

Date: August 8, 2012	/s/ Mark C. Allen Mark C. Allen Senior Vice President and Chief Financial Officer
Date: August 8, 2012	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer