DENBURY RESOURCES INC
Form 10-Q
May 10, 2013

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 March 31, 2013

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 April 30, 2013
Common Stock, $.001 par value	373,164,760

Denbury Resources Inc.

Table of Contents

Table of Contents
PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

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

	March 31, 2013	December 31, 2012
Assets		
Current assets		
Cash and cash equivalents	$62,269	$98,511
Restricted cash	50,460	1,050,015
Accrued production receivable	249,800	253,131
Trade and other receivables, net	92,111	81,971
Derivative assets	3,981	19,477
Deferred tax assets	24,799	29,156
Other current assets	16,426	10,493
Total current assets	499,846	1,542,754
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	7,953,604	6,963,211
Unevaluated	1,075,910	809,154
CO_2 properties	1,048,002	1,032,653
Pipelines and plants	2,070,841	2,035,126
Other property and equipment	416,885	417,207
Less accumulated depletion, depreciation, amortization, and impairment	(3,279,541)	(3,180,241)
Net property and equipment	9,285,701	8,077,110
Derivative assets	395	36
Goodwill	1,283,590	1,283,590
Other assets	247,233	235,852
Total assets	$11,316,765	$11,139,342
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$344,187	$414,668
Oil and gas production payable	174,369	161,945
Derivative liabilities	7,672	2,842
Current maturities of long-term debt	34,033	36,966
Total current liabilities	560,261	616,421
Long-term liabilities		
Long-term debt, net of current portion	3,262,499	3,104,462
Asset retirement obligations	112,674	102,730
Derivative liabilities	15,560	23,781
Deferred taxes	2,192,946	2,153,452
Other liabilities	26,945	23,607
Total long-term liabilities	5,610,624	5,408,032
Commitments and contingencies (Note 7)		
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; 408,246,533 and 406,163,194 shares issued, respectively	408	406
Paid-in capital in excess of par	3,149,887	3,136,461
Retained earnings	2,522,406	2,434,835
Accumulated other comprehensive loss	(328)	(348)
Treasury stock, at cost, 34,715,913 and 30,601,262 shares, respectively	(526,493)	(456,465)
Total stockholders' equity	5,145,880	5,114,889
Total liabilities and stockholders' equity	$11,316,765	$11,139,342

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

Denbury Resources Inc.
Unaudited Condensed Consolidated Statements of Operations
(In thousands, except per share data)

	Three Months Ended March 31,	
	2013	2012
Revenues and other income		
Oil, natural gas, and related product sales	$573,653	$633,501
CO_2 sales and transportation fees	6,558	6,795
Interest income and other income	2,875	4,820
Total revenues and other income	583,086	645,116
Expenses		
Lease operating expenses	140,542	137,964
Marketing expenses	9,796	10,830
CO_2 discovery and operating expenses	3,722	6,205
Taxes other than income	38,011	43,694
General and administrative expenses	41,889	36,607
Interest, net of amounts capitalized of $21,705 and $19,445, respectively	36,034	36,314
Depletion, depreciation, and amortization	112,898	120,895
Derivatives expense (income)	11,929	45,275
Loss on early extinguishment of debt	44,223	—
Impairment of assets	—	17,300
Other expenses	2,107	10,720
Total expenses	441,151	465,804
Income before income taxes	141,935	179,312
Income tax provision	54,364	65,845
Net income	$87,571	$113,467
Net income per common share – basic	$0.24	$0.29
Net income per common share – diluted	$0.23	$0.29
Weighted average common shares outstanding		
Basic	369,396	386,367
Diluted	372,867	390,943

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

Denbury Resources Inc.
Unaudited Condensed Consolidated Statements of Comprehensive Operations
(In thousands)

	Three Months Ended March 31,	
	2013	2012
Net income	$87,571	$113,467
Other comprehensive income, net of income tax:		
Interest rate lock derivative contracts reclassified to income, net of tax of $8 and $11, respectively	20	18
Total other comprehensive income	20	18
Comprehensive income	$87,591	$113,485

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Resources Inc.
Unaudited Condensed Consolidated Statements of Cash Flows
(In thousands)

	Three Months Ended March 31,	
	2013	2012
Cash flow from operating activities		
Net income	$87,571	$113,467
Adjustments to reconcile net income to cash flow from operating activities:		
Depletion, depreciation, and amortization	112,898	120,895
Deferred income taxes	43,845	37,137
Stock-based compensation	7,908	7,913
Noncash fair value derivative adjustments	11,957	44,113
Loss on early extinguishment of debt	44,223	—
Amortization of debt issuance costs and discounts	3,736	3,674
Impairment of assets	—	17,300
Other, net	3,608	7,725
Changes in assets and liabilities, net of effects from acquisitions:		
Accrued production receivable	344	(8,863)
Trade and other receivables	(13,815)	9,162
Other current and long-term assets	(4,756)	676
Accounts payable and accrued liabilities	(33,337)	(32,861)
Oil and natural gas production payable	12,424	(470)
Other liabilities	(7,430)	(28,214)
Net cash provided by operating activities	269,176	291,654
Cash flow used in investing activities:		
Oil and natural gas capital expenditures	(226,917)	(302,246)
Acquisitions of oil and natural gas properties	(101)	(592)
CO_2 capital expenditures	(27,014)	(30,693)
Pipelines and plants capital expenditures	(50,416)	(60,441)
Purchases of other assets	(14,867)	(4,945)
Net proceeds from sales of oil and natural gas properties and equipment	663	26,572
Proceeds from sale of short-term investments	—	83,545
Other	(1,994)	(83)
Net cash used for investing activities	(320,646)	(288,883)
Cash flow provided by financing activities:		
Bank repayments	(820,000)	(150,000)
Bank borrowings	395,000	210,000
Repayment of senior subordinated notes	(613,064)	—
Premium paid on repayment of senior subordinated notes	(34,660)	—
Proceeds from issuance of senior subordinated notes	1,200,000	—
Costs of debt financing	(20,000)	(11)
Common stock repurchase program	(81,402)	—
Other	(10,646)	(4,087)
Net cash provided by financing activities	15,228	55,902
Net increase (decrease) in cash and cash equivalents	(36,242)	58,673
Cash and cash equivalents at beginning of period	98,511	18,693
Cash and cash equivalents at end of period	$62,269	$77,366

See accompanying 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 the most significant emphasis relating to 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 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, 2012 (the "Form 10-K"). Unless indicated otherwise or the context requires, the terms "we," "our," "us," "Company," or "Denbury," 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 March 31, 2013, our consolidated results of operations for the three months ended March 31, 2013 and 2012, and our consolidated cash flows for the three months ended March 31, 2013 and 2012.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

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 includes the impact of potentially dilutive securities. Potentially dilutive securities consist of stock options, stock appreciation rights ("SARs"), nonvested restricted stock and nonvested performance-based equity awards. For the three months ended March 31, 2013 and 2012, there were no adjustments to net income for purposes of calculating basic and diluted net income per common share.

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:

In thousands	Three Months Ended March 31, 2013	2012
Basic weighted average common shares	369,396	386,367
Potentially dilutive securities:		
Restricted stock, stock options, SARs and performance-based equity awards	3,471	4,576
Diluted weighted average common shares	372,867	390,943

Basic weighted average common shares excludes 4.3 million and 3.9 million shares of nonvested restricted stock during the three months ended March 31, 2013 and 2012, respectively. As these restricted shares vest, 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. Stock options and SARs of 3.7 million shares and 3.2 million shares were not included in the computation of diluted net income per share for the three month periods ended March 31, 2013 and 2012, respectively, as their effect would have been antidilutive.

Recent Accounting Pronouncements

Balance Sheet Offsetting. In December 2011, the Financial Accounting Standards Board ("FASB") issued ASU 2011-11, Disclosure about Offsetting Assets and Liabilities (“ASU 2011-11”). ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities ("ASU 2013-01"). The update clarifies that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with the Derivatives and Hedging topic of the Financial Accounting Standards Board Codification ("FASC"), including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. ASU 2011-11 and ASU 2013-01 became effective for our fiscal year beginning January 1, 2013 and have been applied retrospectively for all comparative periods presented. The adoption of ASU 2011-11 and ASU 2013-01 did not affect our consolidated financial statements, but required additional disclosures in the notes thereto.

Note 2. Acquisitions and Divestitures

Fair Value. 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 intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The fair value of oil and natural gas properties is based on significant inputs not observable in the market, which the FASC Fair Value Measurements and Disclosures topic defines as Level 3 inputs. Key assumptions may include: (1) NYMEX oil and natural gas futures (this input is observable); (2) dollar-per-acre values of recent sale transactions (this input is observable); (3) projections of the estimated quantities of oil and natural gas reserves, including those classified as proved, probable and possible; (4) estimated oil and natural gas pricing differentials; (5) projections of future rates of production; (6) timing and amount of future development and operating costs; (7) projected costs of CO_2 (to a market participant); (8) projected reserve recovery factors; and (9) risk-adjusted discount rates.

2013 Acquisition

Cedar Creek Anticline Acquisition. In January 2013, we entered into an agreement to acquire producing assets in the Cedar Creek Anticline ("CCA") of Montana and North Dakota from a wholly-owned subsidiary of ConocoPhillips Company ("ConocoPhillips") for $1.05 billion. On March 27, 2013, we closed the acquisition for $989.0 million in cash after preliminary closing adjustments, primarily for revenues and costs of the purchased properties from the January 1, 2013 effective date to the closing date. We funded the acquisition with a portion of the cash proceeds from the Bakken Exchange Transaction (described below) from which $1.05 billion was placed in qualifying trust accounts in order to qualify the acquisition for like-kind-exchange treatment under federal income tax rules. This $1.05 billion of cash was classified as Restricted Cash in our December 31, 2012 Consolidated Balance Sheet. This acquisition meets the definition of a business under the FASC Business Combinations topic. As such, we estimated the fair value of assets acquired and liabilities assumed as of March 27, 2013, the closing date of the acquisition, using a discounted future net cash flow model. The current purchase price allocation is preliminary, pending final closing adjustments, and further evaluation of the oil and natural gas properties, other assets and related asset retirement obligations.

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

The following table presents a summary of the preliminary fair value of assets acquired and liabilities assumed in the CCA acquisition:

In thousands	
Consideration:	
Cash payment (1)	$988,982
Fair value of assets acquired and liabilities assumed:	
Oil and natural gas properties	
Proved	771,487
Unevaluated	222,820
Other assets	1,884
Asset retirement obligations	(7,209)
	$988,982

(1) This cash payment was made through a qualified intermediary from cash placed in qualifying trust accounts from a portion of the proceeds received from the Bakken Exchange Transaction (as defined below) in order to enable a like-kind-exchange transaction for federal income tax purposes. As such, this amount is not reflected as a cash payment to purchase oil and natural gas properties in our Unaudited Condensed Consolidated Statement of Cash Flows.

2012 Acquisitions and Divestitures

Bakken Exchange Transaction. In late 2012, we closed a sale and exchange transaction (the "Bakken Exchange Transaction") with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, “ExxonMobil”) in which we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for (1) $1.3 billion in cash (after preliminary closing adjustments), (2) ExxonMobil's operating interests in Webster Field in Texas and Hartzog Draw Field in Wyoming, and (3) approximately a one-third overriding royalty ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming. No adjustments were made during the first quarter of 2013 to the preliminary fair value of the assets acquired and liabilities assumed as previously disclosed in our Form 10-K.

Thompson Field Acquisition. In June 2012, we acquired a nearly 100% working interest and 84.7% net revenue interest in Thompson Field for $366.2 million after closing adjustments. 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.

Unaudited Pro Forma Acquisition Information. The following combined pro forma total revenues and other income and net income are presented as if the CCA Acquisition, Bakken Exchange Transaction and Thompson Field acquisition had occurred on January 1, 2012:

	Three Months Ended March 31,	
In thousands, except per share data	2013	2012
Pro forma total revenues and other income	$665,260	$686,049
Pro forma net income	115,591	133,531
Pro forma net income per common share		
Basic	$0.31	$0.35

Diluted	0.31	0.34

Table of Contents
Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Other 2012 Divestiture. In February 2012, we completed the sale of certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for net proceeds of $141.8 million, after final closing adjustments. The sale had an effective date of December 1, 2011, and we did not record a gain or loss on the sale in accordance with the full cost method of accounting.

Note 3. Long-Term Debt

The following long-term debt and capital lease obligations were outstanding as of the dates indicated:

In thousands	March 31, 2013	December 31, 2012
Bank Credit Agreement	$275,000	$700,000
9½% Senior Subordinated Notes due 2016, including premium of $1,437 and $9,118, respectively	39,643	234,038
9¾% Senior Subordinated Notes due 2016, including discount of $13,569	—	412,781
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6 3/8% Senior Subordinated Notes due 2021	400,000	400,000
4 5/8% Senior Subordinated Notes due 2023	1,200,000	—
Other Subordinated Notes, including premium of $23 and $25, respectively	3,829	3,832
Pipeline financings	234,032	236,244
Capital lease obligations	147,755	158,260
Total	3,296,532	3,141,428
Less: current obligations	(34,033)	(36,966)
Long-term debt and capital lease obligations	$3,262,499	$3,104,462

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. Each of the subsidiary guarantors of such notes is 100% owned, directly or indirectly, by DRI; any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries, and the guarantees of the notes are full and unconditional and joint and several.

4 5/8% Senior Subordinated Notes due 2023

In February 2013, we issued $1.2 billion of 4 5/8% Senior Subordinated Notes due 2023 (the “2023 Notes”). The 2023 Notes, which carry a coupon rate of 4.625%, were sold at par. The net proceeds, after issuance costs, of approximately $1.18 billion were used to repurchase or redeem a portion of our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes"), all of our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") (see Repurchase and Redemption of 9½% Notes and 9¾% Notes below) and to pay down a portion of outstanding borrowings on our Bank Credit Facility (as defined below).

The 2023 Notes mature on July 15, 2023, and interest is payable on January 15 and July 15 of each year, commencing July 15, 2013. We may redeem the 2023 Notes in whole or in part at our option beginning January 15, 2018, at the following redemption prices: 102.313% on or after January 15, 2018; 101.542% on or after January 15, 2019; 100.771% on or after January 15, 2020; and 100% on or after January 15, 2021. Prior to January 15, 2016, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2023 Notes at a redemption price of 104.625% with the proceeds of certain equity offerings. In addition, at any time prior to January 15, 2018, we may redeem 100% of the principal amount of the 2023 Notes at a redemption price equal to 100% of the principal amount plus a “make whole” premium and accrued and unpaid interest. The indenture for the 2023 Notes (the "2023 Indenture") contains certain restrictions on our ability to take or permit certain actions, including restrictions on our ability to: (1) incur additional debt; (2) pay dividends on our common stock or redeem, repurchase or retire such stock or subordinated debt unless certain leverage ratios are met; (3) make investments; (4) create liens on our assets; (5) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to DRI or other restricted subsidiaries; (6) engage in transactions with our affiliates; (7) transfer or sell assets; and (8) consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries. Although the covenants contained in our other senior subordinated notes indentures are generally consistent with those contained in our 2023 Indenture, the 2023 Indenture covenants permit us in certain circumstances to make restricted payments exceeding the amount allowed under our other senior subordinated notes indentures. Under the 2023 Indenture, these restricted payments, which include share repurchases and dividend payments, do not reduce our restricted payment limitation, provided we maintain (both before and after giving effect to any such payment) a predefined leverage ratio of at least 2.5 to 1.

Repurchase and Redemption of 9½% Notes and 9¾% Notes

On January 22, 2013, we commenced cash tender offers to purchase the outstanding $426.4 million principal amount of our 9¾% Notes at 105.425% of par and the outstanding $224.9 million principal amount of our 9½% Notes at 106.869% of par. During February 2013, we accepted for purchase $191.7 million principal amount of the outstanding 9¾% Notes and $186.7 million principal amount of the outstanding 9½% Notes. We received sufficient consents in the solicitation to amend the indenture governing the 9½% Notes to eliminate most of the restrictive covenants and certain events of default. The purchases under these tender offers were funded by a portion of the proceeds received from the issuance of our 2023 Notes. The tender offers expired on February 19, 2013.

On February 5, 2013, we issued a notice of redemption for the remaining $234.7 million principal amount outstanding of our 9¾% Notes at 104.875% of par, and on March 7, 2013, we repurchased all of the remaining 9¾% Notes outstanding. On March 28, 2013, we issued an irrevocable notice of redemption for the remaining $38.2 million principal amount outstanding of our 9½% Notes at 104.75% of par, and on May 1, 2013, we repurchased all of the remaining 9½% Notes outstanding.

We recognized a $44.2 million loss associated with the debt repurchases during the first quarter of 2013, which loss consists of both premium payments made to repurchase or redeem the 9¾% Notes and 9½% Notes and the elimination of unamortized debt issuance costs, discounts and premiums related to the notes. The loss is included in our Unaudited Condensed Consolidated Statement of Operations under the caption "Loss on early extinguishment of debt".

$1.6 Billion Revolving Credit Agreement

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 and upon requested special redeterminations. The borrowing base is adjusted at the banks' discretion and is based in part upon external factors over which we have no control. If the borrowing base were to be less than outstanding borrowings under the Bank Credit Agreement, we would be required to repay the deficit over a period not to exceed four months. As part of the semi-annual review completed on May 1, 2013 pursuant to the terms of the Bank Credit Agreement, our borrowing base was reaffirmed at $1.6 billion. Our next semi-annual redetermination is scheduled to occur on or around November 1, 2013. The weighted average interest rate on borrowings under this revolving credit facility, evidenced by the Bank Credit Agreement (the "Bank Credit Facility") was 1.71% for the three months ended March 31, 2013. 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. Loans under the Bank Credit Facility mature in May 2016.

Note 4. Share Repurchase Program

During the first quarter of 2013, we repurchased 3.9 million shares of Denbury common stock under our board-authorized share repurchase program for $66.2 million, or $16.80 per share. Since commencement of the share repurchase program in October 2011 through March 31, 2013, we have purchased a total of 35.0 million shares of Denbury common stock for $528.1 million, or $15.08 per share. As of March 31, 2013, we have $243.1 million remaining under our authorized share repurchase program.

Note 5. Derivative Instruments

Oil and Natural Gas Derivative Contracts

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 expense (income)” in our Unaudited Condensed Consolidated Statements of Operations.

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 two years in the future from the current quarter, 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 do not have any natural gas derivative contracts for 2013 or beyond. Because our current and forecasted production is primarily oil, we currently use only oil derivative contracts in our commodity market risk management program.

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

	Three Months Ended March 31,	
In thousands	2013	2012
Oil		
Cash payment on settlements of derivative contracts	$—	$8,230
Noncash fair value adjustments to derivative contracts – expense	11,929	42,445
Total derivatives expense – oil	11,929	50,675
Natural Gas		
Cash receipt on settlements of derivative contracts	—	(7,040)
Noncash fair value adjustments to derivative contracts – expense	—	1,640
Total derivatives income – natural gas	—	(5,400)
Derivatives expense (income)	$11,929	$45,275

Denbury Resources Inc.
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 March 31, 2013:

				Contract Prices per Barrel		
		Type of	Volume		Weighted Average Price	
Year	Months	Contract	(Barrels per day)	Range	Floor	Ceiling
Oil contracts:						
2013	Apr – June	Collar	56,000	$ 75.00 – 121.50	$79.64	$108.61
	July – Sept	Collar	56,000	75.00 – 133.10	79.64	109.15
	Oct – Dec	Collar	54,000	80.00 – 127.50	80.00	117.53
2014	Jan – Mar	Collar	52,000	$ 80.00 – 104.50	$80.00	$102.44
	Apr – June	Collar	52,000	80.00 – 104.50	80.00	102.44
	July – Sept	Collar	48,000	80.00 – 98.80	80.00	97.46
	Oct – Dec	Collar	48,000	80.00 – 98.80	80.00	97.46
2015	Jan – Mar	Collar	9,000	$ 80.00 – 100.90	$80.00	$100.59

Additional Disclosures about Derivative Instruments

At March 31, 2013 and December 31, 2012, we had derivative financial instruments recorded in our Unaudited Condensed Consolidated Balance Sheets as follows:

		Estimated Fair Value Asset (Liability)	
Type of Contract	Balance Sheet Location	March 31, 2013	December 31, 2012
		In thousands	
Derivatives not designated as hedging instruments:			
Derivative assets			
Crude oil contracts	Derivative assets – current	$3,981	$19,477
Crude oil contracts	Derivative assets – long-term	395	36
Derivative liabilities			
Crude oil contracts	Derivative liabilities – current	(7,672)	(2,659)
Deferred premiums	Derivative liabilities – current	—	(183)
Crude oil contracts	Derivative liabilities – long-term	(15,560)	(23,781)
Total derivatives not designated as hedging instruments		$(18,856)	$(7,110)

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, and all of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement. The majority of those derivative contracts are subject to enforceable master netting arrangements whereby payables on those contracts can be offset against receivables from separate derivative contracts with the same counterparty. It is

- 13 -

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

our policy to classify derivative assets and liabilities on a gross basis on our balance sheets, even if the contracts are subject to enforceable master netting arrangements. The following table details the March 31, 2013 and December 31, 2012 asset and liability positions of those derivative contracts which are subject to enforceable master netting arrangements:

In thousands	March 31, 2013	December 31, 2012
Derivatives subject to enforceable master netting arrangements:		
Assets	$3,009	$14,059
Liabilities	17,273	19,964

Note 6. Fair Value Measurements

The FASC Fair Value Measurements and Disclosures topic defines fair value as the price that would be received to sell an asset or would be 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. We currently have no Level 1 recurring measurements.

- 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 derivatives that are based on NYMEX pricing. Our 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.

- 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. We currently have no Level 3 recurring measurements.

We adjust the valuations from the valuation model for nonperformance risk, using our estimate of the counterparty’s credit quality for asset positions and our credit quality for liability positions. We use 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
March 31, 2013				
Assets:				
Oil derivative contracts	$—	$4,376	$—	$4,376
Liabilities:				
Oil derivative contracts	—	(23,232)	—	(23,232)
Total	$—	$(18,856)	$—	$(18,856)
December 31, 2012				
Assets:				
Oil derivative contracts	$—	$19,513	$—	$19,513
Liabilities:				
Oil derivative contracts	—	(26,440)	—	(26,440)
Total	$—	$(6,927)	$—	$(6,927)

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 expense (income)” in our Unaudited Condensed Consolidated Statements of Operations.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

During the three months ended March 31, 2012, we recorded a $15.1 million impairment charge for an investment in the preferred stock of Faustina Hydrogen Products LLC, which impairment was classified as “Impairment of assets” in the Unaudited Condensed Consolidated Statement of Operations for the three months ended March 31, 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. We use a market approach to determine fair value of our fixed-rate debt using observable market data. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our total long-term debt as of March 31, 2013 and December 31, 2012, excluding pipeline financing and capital lease obligations, is $3,026.8 million and $2,956.9 million, respectively. 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 7. 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.

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 Unaudited Condensed Consolidated Financial Statements and Notes thereto included herein and our Consolidated Financial Statements and Notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2012 (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 section for information on the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

OVERVIEW

Our primary focus is on enhanced oil recovery utilizing CO_2, and our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. We are the largest combined oil and natural gas producer in both Mississippi and Montana, and we own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River. 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 relating to tertiary recovery operations.

Operating Highlights. The first quarter of 2013 was a transitional quarter as we sold our Bakken area assets in the fourth quarter of 2012, and while we entered into an agreement to purchase additional interests in the Cedar Creek Anticline ("CCA") with these funds in early January, the acquisition did not close until late March as we expected. Had we acquired CCA on January 1, 2013 and thus benefited from a full quarter of production from the acquisition, we estimate that our pro forma first quarter 2013 production would have averaged approximately 74,000 BOE/d instead of our actual production of 63,823 BOE/d. These lower actual production levels during the first quarter of 2013, resulting from the time lag between our Bakken asset sale and the completion of the CCA acquisition, negatively impacted our income and operating cash flows during the first quarter.

We recognized net income of $87.6 million, or $0.23 per diluted common share, during the first quarter of 2013 compared to net income of $113.5 million, or $0.29 per diluted common share, during the first quarter of 2012. This decrease in net income between the two periods is primarily attributable to a $59.8 million decrease in oil and natural gas revenues due to the aforementioned lower total production resulting from the sale of properties in 2012 and a $44.2 million ($27.2 million after-tax) loss on the early extinguishment of debt in the current year quarter related to our debt refinancing (see Debt Refinancing below for further discussion), partially offset by reduced expense of $32.2 million ($19.8 million after-tax) in the current year period due to the noncash change in the fair value adjustment of our commodity derivative contracts and the absence in the first quarter of 2013 of a $17.3 million ($10.7 million after-tax) impairment charge incurred during the comparable period in 2012.

During the first quarter of 2013, our oil and natural gas production, which was 93% oil, averaged 63,823 BOE/d compared to 71,532 BOE/d produced during the first quarter of 2012. This 11% decrease in total production is primarily attributable to properties sold in 2012, partially offset by strong production increases from our tertiary oil fields, which reached record production levels in the first quarter of 2013, plus incremental production from three fields acquired during 2012. We closed our acquisition of additional CCA properties from ConocoPhillips on March 27, 2013; production from this acquisition (which was averaging approximately 11,000 BOE/d net to us at that time) contributed approximately 500 BOE/d to the first quarter 2013 production as only four days of production from these properties was included in our first quarter results. After adjusting quarterly production to exclude production from non-core properties sold in 2012, production in the first quarter of 2013 increased 17% over production in the comparable prior-year quarter and 6% sequentially over levels in the fourth quarter of 2012. Our tertiary oil production averaged 39,057 Bbls/d during the first quarter of 2013, an increase of 17% over the 33,257 Bbls/d produced during the first quarter of 2012 and an increase of 4% compared to fourth quarter 2012 levels. See Results of Operations – Operating Results Summary – Production for more information.

Our average realized oil price per barrel, excluding the impact of commodity derivative contracts, increased 3% to $105.59 per Bbl during the first quarter of 2013, compared to $102.52 per Bbl during the first quarter of 2012. However, NYMEX oil prices decreased 8% between the respective first quarters of 2012 and 2013, resulting in our average oil price differential compared to the NYMEX benchmark improving to a positive $11.17 per Bbl in the first quarter of 2013, compared to a negative $0.37 per

Bbl in the first quarter of 2012. The improved oil price differential realized this quarter is primarily due to the change in the mix of our properties subsequent to the disposition of our Bakken properties in late 2012, as a larger percentage of our production was subject to LLS index prices in the first quarter of 2013. See Results of Operations – Operating Results Summary – Oil and Natural Gas Revenues below for more information on our oil prices received and differentials to NYMEX prices.

Cedar Creek Anticline Acquisition. On March 27, 2013, we closed our acquisition of producing assets in the CCA of Montana and North Dakota in a purchase from a wholly-owned subsidiary of ConocoPhillips Company ("ConocoPhillips") for $989.0 million in cash, after preliminary standard closing adjustments, primarily for revenues and costs of the properties purchased from the January 1, 2013 effective date to the closing date. We funded the acquisition with a portion of the cash proceeds from the Bakken exchange transaction from which $1.05 billion was placed in qualifying trust accounts in order to qualify the acquisition for like-kind-exchange treatment under federal income tax rules. The assets purchased include both additional interests in certain of our existing operated fields in CCA, as well as operating interests in other CCA fields. In conjunction with this acquisition, we added 42.2 MMBOE of estimated proved reserves.

Rocky Mountain Tertiary Operations Startup. In late 2012, we completed construction of the first section of the 20-inch Greencore Pipeline in Wyoming, our first CO_2 pipeline in the Rocky Mountain region, and received the first CO_2 deliveries from the Lost Cabin gas plant in central Wyoming during the first quarter of 2013. We currently expect to start injections at our Bell Creek Field in Montana during the second quarter of 2013, and our first tertiary production from this field to commence in the second half of 2013. In December 2012, we completed the required three-mile CO_2 pipeline to deliver CO_2 from our source at LaBarge Field to Grieve Field in Wyoming and began injecting CO_2 into Grieve Field during the first quarter of 2013. We currently do not expect any tertiary production from Grieve Field until 2015.

Debt Refinancing. In February 2013, we issued $1.2 billion of 4 5/8% Senior Subordinated Notes due 2023 (the "2023 Notes"). The net proceeds of approximately $1.18 billion were used to repurchase or redeem a portion of our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes"), all of our 9¾% Senior Subordinated notes due 2016 (the "9¾% Notes") and to pay down a portion of outstanding borrowings on our bank credit facility. On May 1, 2013, we redeemed all of the remaining outstanding 9½% Notes at 104.75% of par. During the first quarter of 2013, we recognized a $44.2 million loss associated with the first quarter of 2013 debt repurchases, which is included in our Unaudited Condensed Consolidated Statement of Operations under the caption "Loss on early extinguishment of debt". See Note 3, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements for additional details surrounding the repurchase and redemption of our 9½% Notes and 9¾% Notes.

CAPITAL RESOURCES AND LIQUIDITY

2013 Capital Spending. We have recently reviewed our 2013 capital spending plans and, as a result of the CCA acquisition and capital projects carried over from 2012, we have increased our 2013 capital budget by $60 million, from $1.0 billion to $1.06 billion, excluding acquisitions. In addition, we currently estimate spending approximately $160 million in capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production start-up costs associated with new tertiary floods, which is up from our previous estimate for these costs of $125 million. Our current 2013 capital budget is comprised of the following:

- $580 million allocated for tertiary oil field expenditures;
- $110 million for pipeline construction;

- \$200 million to be spent on CO_2 sources;
- \$170 million to be spent in all other areas; and
- \$160 million for other capital items such as capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production start-up costs associated with new tertiary floods.

During the three months ended March 31, 2013, we incurred capital expenditures of approximately \$270.9 million, exclusive of property acquisitions and capitalized interest. See additional detail on our expenditures in the Capital Expenditure Summary below.

Based on oil and natural gas commodity futures prices in early May 2013 and our current production forecast (including production from the CCA Acquisition), we estimate that our anticipated 2013 cash flow from operations should be adequate to cover our 2013 capital budget. If prices were to decrease or changes in operating results were to cause us to have a significant reduction in anticipated 2013 cash flows, we have ample availability on our bank credit facility to cover any potential shortfall, and we also have the ability to reduce our capital expenditures if desired. In addition, we have oil derivative contracts in place with an $80 NYMEX floor price for a significant portion of our anticipated oil production for 2013 and 2014 to provide an economic hedge of our exposure to commodity prices (see Note 5, Derivative Instruments to the Unaudited Condensed Consolidated Financial Statements for details of our oil commodity contacts).

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. For 2013 and some 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 of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments and Obligations in the Form 10-K).

Bank Credit Facility. Our primary sources of capital are our cash flow from operations and borrowings under our bank credit facility. As part of our semiannual bank review, in early May 2013 the borrowing base for our bank credit facility was reaffirmed at $1.6 billion. Our next borrowing base redetermination is scheduled on or around November 1, 2013. We currently do not anticipate any reduction in our borrowing base as part of that redetermination, and we believe, based on current commodity prices and our proved asset base, that we could obtain lender approval to significantly increase the borrowing base under our bank credit facility above the current $1.6 billion level if we desired to do so. As of March 31, 2013, we had $1.3 billion of unused availability under our bank credit facility and cash of $62.3 million, leaving us significant liquidity to fund any cash shortfall for capital expenditures.

Share Repurchase Program. Our Board of Directors has approved a common share repurchase program for up to $771.2 million of our common shares. Since commencement of the share repurchase program in October 2011 through April 30, 2013, we have purchased a total of 35.8 million shares of Denbury common stock for $541.9 million, or $15.13 per share. As of April 30, 2013, we have $229.3 million remaining under our authorized share repurchase program. See Note 4, Share Repurchase Program to the Unaudited Condensed Consolidated Financial Statements for further discussion. Our share repurchases will be determined based on various parameters; therefore, our share repurchases may be less than the remaining approved balance under the program and there is no set expiration date for our program. We anticipate that additional repurchases during 2013 will be primarily funded with excess cash flow from operations or with borrowings under our bank credit facility.

Capital Expenditure Summary. The following table of capital expenditures includes accrued capital for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
In thousands	2013	2012
Capital expenditures by project:		
Tertiary oil fields	$169,829	$113,578
CO_2 pipelines	8,818	14,151
CO_2 sources [1]	30,266	50,479
Other areas	61,997	162,555
Capital expenditures before acquisitions and capitalized interest	270,910	340,763
Less: recoveries from sale/leaseback transactions	—	(21,002)

Net capital expenditures excluding acquisitions and capitalized interest	270,910	319,761
Property acquisitions [2]	999,859	1,234
Capitalized interest	21,705	19,445
Capital expenditures, net of sale/leaseback transactions	$1,292,474	$340,440

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

Table of Contents
Denbury Resources Inc.
Management’s Discussion and Analysis of Financial Condition and Results of Operations

(2) Property acquisitions during the three months ended March 31, 2013 include capital expenditures of approximately $1.0 billion related to acquisitions during the period 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 other than property acquisitions for the first three months of 2013 were funded with cash flow from operations, and our property acquisitions were funded with proceeds from the Bakken exchange transaction, which closed in late 2012 for which a portion of the proceeds were placed in qualifying trust accounts in order to qualify the acquisition as a like-kind-exchange transaction under federal income tax rules. Our capital expenditures for the first three months of 2012 were funded with $291.7 million of cash flow from operations and the remainder with borrowings under our bank credit facility.

Off-Balance Sheet Arrangements. Our off-balance sheet arrangements include operating leases for office space and various obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry, none of which are recorded on our balance sheet. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs estimated in our proved reserve reports.

Our commitments and obligations consist of those detailed as of December 31, 2012 in the Form 10-K under Management’s Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments and Obligations.

RESULTS OF OPERATIONS

Our tertiary operations represent a significant portion of our overall operations and is our primary strategic focus. The economics of a tertiary field and the related impact on our financial statements differ from a conventional oil and gas play, and we have outlined certain of these differences in our Form 10-K and other public disclosures. Our focus on these types of operations impacts certain trends in both current and long-term operating results. Please refer to Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Financial Overview of Tertiary Operations in our Form 10-K for further information regarding these matters.

Table of Contents
Denbury Resources Inc.
Management’s Discussion and Analysis of Financial Condition and Results of Operations

Operating Results Summary

Certain of our operating results and statistics for the comparative first quarters of 2013 and 2012 are included in the following table:

	Three Months Ended March 31,	
In thousands, except per share and unit data	2013	2012
Operating results		
Net income	$87,571	$113,467
Net income per common share – basic	0.24	0.29
Net income per common share – diluted	0.23	0.29
Net cash provided by operating activities	269,176	291,654
Average daily production volumes		
Bbls/d	59,577	66,857
Mcf/d	25,477	28,052
BOE/d (1)	63,823	71,532
Operating revenues		
Oil sales	$566,143	$623,706
Natural gas sales	7,510	9,795
Total oil and natural gas sales	$573,653	$633,501
Commodity derivative contracts (2)		
Cash payment on settlements of derivative contracts	$—	$(1,190)
Noncash fair value adjustments to derivative contracts – expense	(11,929)	(44,085)
Total expense from commodity derivative contracts	$(11,929)	$(45,275)
Unit prices – excluding impact of derivative settlements		
Oil price per Bbl	$105.59	$102.52
Natural gas price per Mcf	3.28	3.84
Unit prices – including impact of derivative settlements (2)		
Oil price per Bbl	$105.59	$101.16
Natural gas price per Mcf	3.28	6.59
Oil and natural gas operating expenses		
Lease operating expenses	$140,542	$137,964
Marketing expenses	9,796	10,830
Production and ad valorem taxes	35,420	41,054
Oil and natural gas operating revenues and expenses per BOE (1)		
Oil and natural gas revenues	$99.87	$97.32
Lease operating expenses	24.47	21.19
Marketing expenses, net of third-party purchases	1.41	1.66
Production and ad valorem taxes	6.17	6.31
CO_2 revenues and expenses		
CO_2 sales and transportation fees	$6,558	$6,795
CO_2 discovery and operating expenses (3)	(3,722)	(6,205)
CO_2 revenue and expenses, net	$2,836	$590

(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 $4.9 million of exploratory costs during the three months ended March 31, 2012.

Production

Average daily production by area for each of the four quarters of 2012 and for the first quarter of 2013 is shown below:

	Average Daily Production (BOE/d)				
Operating Area	First Quarter 2012	Second Quarter 2012	Third Quarter 2012	Fourth Quarter 2012	First Quarter 2013
Tertiary oil production					
Gulf Coast region					
Mature properties:					
Brookhaven	3,014	2,779	2,460	2,520	2,305
Eucutta	3,090	2,870	2,782	2,730	2,636
Mallalieu	2,585	2,461	2,181	2,127	2,116
Other mature properties (1)	8,012	7,867	7,347	7,605	7,800
Delhi	4,181	4,023	3,813	5,237	5,827
Hastings	618	1,913	2,794	3,409	3,956
Heidelberg	3,583	3,823	3,716	3,930	3,943
Oyster Bayou	877	1,304	1,540	1,826	2,252
Tinsley	7,297	8,168	8,153	8,166	8,222
Total tertiary oil production	33,257	35,208	34,786	37,550	39,057
Non-tertiary oil and gas production					
Gulf Coast region					
Mississippi	4,573	4,095	3,401	3,663	3,013
Texas	3,674	4,573	5,173	5,513	6,692
Other	1,281	1,306	1,137	1,217	1,153
Total Gulf Coast region	9,528	9,974	9,711	10,393	10,858
Rocky Mountain region					
Cedar Creek Anticline	8,496	8,535	8,490	8,493	8,745
Other	3,204	3,060	3,037	3,616	5,163
Total Rocky Mountain region	11,700	11,595	11,527	12,109	13,908
Total non-tertiary production	21,228	21,569	21,238	22,502	24,766
Total continuing production	54,485	56,777	56,024	60,052	63,823
Properties disposed:					
Bakken area assets (2)	15,285	15,503	16,752	10,064	—
2012 Non-core asset divestitures (3)	1,762	57	—	—	—
Total production	71,532	72,337	72,776	70,116	63,823

(1) Other mature properties include Cranfield, Little Creek, Lockhart Crossing, Martinville, McComb and Soso fields.
(2) Includes production from certain Bakken area assets sold in the fourth quarter of 2012.
(3)

Includes production from certain non-core Gulf Coast assets sold in late February 2012 and certain non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012.

Total Production

As outlined in the above table, continuing production increased 9,338 BOE/d (17%) during the three months ended March 31, 2013 over production levels in the 2012 comparable period, and increased 3,771 BOE/d (6%) compared to fourth quarter 2012 production levels. Continuing production increases were primarily due to production increases from our tertiary oil fields, coupled with incremental production from three fields acquired during 2012, and was partially offset by normal declines in our mature tertiary fields and other non-tertiary fields. Our acquisition of additional CCA properties purchased from ConocoPhillips closed on March 27, 2013; therefore, production from this acquisition (which was averaging approximately 11,000 BOE/d net to us at the time of acquisition) contributed approximately 500 BOE/d to first quarter 2013 production as only four days of production from these properties was included, but will significantly impact our production during the second quarter.

Total production decreased 7,709 BOE/d (11%) during the three months ended March 31, 2013 compared to first quarter 2012 levels and 6,293 BOE/d (9%) compared to fourth quarter 2012 production levels, due to non-core asset sales during 2012. Our production during the three months ended March 31, 2013 was 93% oil, consistent with oil production during the three months ended March 31, 2012.

Tertiary Production

Oil production from our tertiary operations increased to record levels during the first quarter of 2013, averaging 39,057 Bbls/d, a 17% increase compared to first quarter 2012 tertiary production levels and an increase of 1,507 Bbls/d (4%) compared to fourth quarter 2012 production levels. The tertiary production increases were primarily due to production growth in response to continued field development and expansion of facilities in the tertiary floods in Delhi, Hastings, and Oyster Bayou fields. During the latter half of 2013, we expect our share of production at Delhi Field to decrease by approximately 25% due to the impact of a reversionary interest; however, we anticipate the decrease in production will be offset by production growth at certain of our tertiary floods.

Non-Tertiary Production

Continuing production from our non-tertiary operations increased to an average of 24,766 BOE/d during the first quarter of 2013, an increase of 3,538 BOE/d (17%) compared to first quarter 2012 non-tertiary continuing production levels and an increase of 2,264 BOE/d (10%) compared to fourth quarter of 2012 levels. The non-tertiary continuing production increases were primarily due to production from newly acquired fields, specifically Webster and Hartzog Draw fields acquired in the Bakken exchange transaction in late 2012 and Thompson Field acquired in June 2012. Production from CCA also increased slightly during the first quarter of 2013 due to our March 27, 2013 acquisition of additional interests in certain of our existing operated fields in CCA, as well as operating interests in other CCA fields. Production from these acquired CCA interests contributed approximately 500 BOE/d to first quarter 2013 production, as only four days of production from these properties was included. With the exception of the impact of production added from fields acquired during 2012 and the 2013 CCA acquisition, production from our other non-tertiary properties is generally on decline, and in some instances the decline may appear larger than normal due to the expansion of our tertiary floods in certain fields which causes non-tertiary production generally to be shut in for a period while the field is being pressured up.

Table of Contents
Denbury Resources Inc.
Management's Discussion and Analysis of Financial Condition and Results of Operations

Oil and Natural Gas Revenues

Our oil and natural gas revenues decreased 9% during the three months ended March 31, 2013, compared to these revenues for the same period in 2012. The decrease is related to declines in total production, partially offset by a slight increase in commodity prices. The change in oil and natural gas revenues due to these factors, excluding any impact of our derivative contracts, are reflected in the following table:

	Three Months Ended March 31, 2013 vs. 2012	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:		
Decrease in production	$(74,486)	(11)%
Increase in commodity prices	14,638	2%
Total decrease in oil and natural gas revenues	$(59,848)	(9)%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
	2013	2012
Net realized prices:		
Oil price per Bbl	$105.59	$102.52
Natural gas price per Mcf	3.28	3.84
Price per BOE	99.87	97.32
NYMEX differentials:		
Oil per Bbl	$11.17	$(0.37)
Natural gas per Mcf	(0.21)	1.32

As reflected in the table above, our average net realized oil price increased 3% during the first quarter of 2013, compared to the average price received during the first quarter of 2012. Company-wide oil price differentials in the first quarter of 2013 were $11.17 per Bbl above NYMEX, compared to an average differential of $0.37 per Bbl below NYMEX in the first quarter of 2012 and $9.43 per Bbl above NYMEX in the fourth quarter of 2012. The net differential we received was primarily impacted by positive differentials in the Gulf Coast region, offset by unfavorable differentials in the Rocky Mountain region, each of which is discussed in further detail below.

We received favorable NYMEX oil differentials in the Gulf Coast region during the three months ended March 31, 2013 and 2012, primarily due to the favorable differential for crude oil sold under Light Louisiana Sweet ("LLS") index prices. This LLS-to-NYMEX differential averaged a positive $20.15 per Bbl on a trade-month basis for the first quarter of 2013, compared to a positive $12.55 per Bbl in the first quarter of 2012 and a positive $20.08 per Bbl in the fourth quarter of 2012. 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. While this differential is significant in the pricing for our oil production, other market and contractual 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 as infrastructure is added to move barrels of oil from the U.S. Mid-continent market to the Gulf Coast region. In fact, during late April 2013, the LLS premium to NYMEX has decreased to around $11 positive to NYMEX.

NYMEX oil differentials in the Rocky Mountain region during the first quarter of 2013 were $4.49 per Bbl below NYMEX, compared to an average differential of $14.54 per Bbl below NYMEX in the first quarter of 2012. The change in the differential between the two periods was largely impacted by the sale of our Bakken area assets in December 2012, as oil sales related to these properties sold at a significant discount to NYMEX during the first quarter of 2012 due to increased production in the area coupled with limited transportation infrastructure.

During the first quarter of 2013, we sold approximately 53% of our crude oil at prices based on the LLS index price, approximately 26% at prices partially tied to the LLS index price, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region. We currently expect our company-wide differentials in future periods to be negatively impacted by incremental production from our newly acquired CCA assets since our CCA production has historically sold at a discount to NYMEX.

Oil and Natural Gas Derivative Contracts

The following tables summarize the impact our oil and natural gas derivative contracts had on our operating results for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,					
	2013	2012	2013	2012	2013	2012
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Cash settlement receipts (payments)	$—	$(8,230)	$—	$7,040	$—	$(1,190)
Noncash fair value loss	(11,929)	(42,445)	—	(1,640)	(11,929)	(44,085)
Total	$(11,929)	$(50,675)	$—	$5,400	$(11,929)	$(45,275)

Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our oil and natural gas derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period change in the fair value of these contracts, as outlined above, are recognized in our statements of operations. Our derivative contracts for 2013 and beyond are currently all NYMEX oil contracts given that our current and forecasted production is primarily oil (93% of volumes on a BOE-basis in the first quarter of 2013), leading us to focus primarily on oil derivative contracts in our commodity market risk management program. We may enter into natural gas derivative contracts in the future as the natural gas market improves and as we anticipate our natural gas production will increase with the expected start up of Riley Ridge gas production later this year. See Notes 5 and 6 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

Production Expenses

Lease operating expense

	Three Months Ended March 31,	
In thousands, except per-BOE data	2013	2012
Lease operating expense		
Tertiary	$86,808	$80,931
Non-tertiary	53,734	57,033
Total lease operating expense	$140,542	$137,964
Lease operating expense per BOE		
Tertiary	$24.70	$26.74
Non-tertiary	24.11	16.37
Total lease operating expense per BOE	24.47	21.19

Total lease operating expense during the first quarter of 2013 increased approximately 2% on an absolute-dollar basis compared to the comparable prior-year period as increases in tertiary lease operating expense were partially offset by reductions in non-tertiary lease operating expense due to the sale of our Bakken area assets in late 2012. On a per-BOE basis, total lease operating expense per BOE increased approximately $3.30 as the approximate $2.00 per-BOE decline in tertiary lease operating expense more than offset the approximate $7.70 per BOE increase in non-tertiary lease operating expense. Although our acquisition of additional interests in CCA late in the first quarter of 2013 will result in an increase in total lease operating expense in future quarters, we do not expect the CCA acquisition to have a significant impact on our lease operating expense per BOE.

Tertiary lease operating expense increased $5.9 million during the first quarter of 2013 compared to those in the same period in 2012 primarily due to an increase in CO_2 volumes injected into producing CO_2 fields and increases in the cost of CO_2 between the comparative periods. Currently, our CO_2 expense comprises approximately one-fourth of our typical Gulf Coast tertiary operating expenses, and for the CO_2 reserves we already own, consists of our CO_2 production expenses, and for the CO_2 reserves we do not own, consists of our purchase of CO_2 from royalty and working interest owners and anthropogenic (man-made) sources. During the first quarter of 2013, approximately 76% of the CO_2 utilized in our Gulf Coast region CO_2 floods consisted of CO_2 owned and produced by us and the remaining portion we purchased from third-party owners (primarily royalty owners). The price we pay others for CO_2 varies by source and is generally indexed to oil prices. When combining the production cost of the CO_2 we own with what we pay third parties (primarily royalty owners) for CO_2, our average cost of CO_2 during the first quarter of 2013 was approximately $0.33 per Mcf, including taxes paid on CO_2 production but excluding depreciation and amortization of capital expended at our Jackson Dome source and CO_2 pipelines. This rate during the first quarter of 2013 was higher than the $0.28 per Mcf spent during the first quarter of 2012. Including the cost of depreciation and amortization expense related to the Jackson Dome CO_2 production but excluding depreciation of our CO_2 pipelines, our cost of CO_2 was $0.42 per Mcf and $0.36 per Mcf during the first quarter of 2013 and 2012, respectively.

Tertiary lease operating expense averaged $24.70 per Bbl, an 8% decrease from an average of $26.74 per Bbl during the first quarter of 2012. The decrease in tertiary operating costs per barrel in the first quarter of 2013 compared to the same period in 2012 is due to the 17% increase in tertiary production, primarily due to the production increases at Hastings and Oyster Bayou fields. For any specific field, we expect our tertiary lease operating expense per barrel to be high initially, as we experienced early in 2012 with our Oyster Bayou and Hastings floods, 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.

Non-tertiary lease operating expense decreased 6% during the first quarter of 2013 compared to the first quarter of 2012 levels, as declines due to the sale of our Bakken area assets were only partially offset by increases due to our acquisition of additional interests in CCA late in the first quarter of 2013. We expect non-tertiary lease operating expense to increase in future periods due to the acquisition of CCA. On a per-BOE basis, non-tertiary lease operating expense in the first quarter of 2013 increased 47% compared to those in the same quarter in 2012 due to the sale of our Bakken area properties, which had a low operating cost per barrel. The consecutive quarter increase in lease operating expense per BOE (first quarter of 2013 compared to fourth quarter of 2012) was limited to 18% as lease operating expense and related production from the Bakken area assets, which were sold during the fourth quarter of 2012, were included in the fourth quarter of 2012 amounts for only a portion of the quarter.

Taxes other than income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income decreased $5.7 million during the first quarter of 2013 compared to the same period in 2012 and remained consistent with fourth quarter of 2012 levels. The change in each period is generally aligned with fluctuations in oil and natural gas revenues.

General and Administrative Expenses (“G&A”)

	Three Months Ended March 31,	
In thousands, except per-BOE data and employees	2013	2012
Gross administrative costs	$84,006	$74,060
Gross stock-based compensation	10,764	10,594
Operator labor and overhead recovery charges	(38,394)	(35,624)
Capitalized exploration and development costs	(14,487)	(12,423)
Net G&A expense	$41,889	$36,607
G&A per BOE:		
Net administrative costs	$6.05	$4.55
Net stock-based compensation	1.24	1.07
Net G&A expense	$7.29	$5.62
Employees as of March 31	1,475	1,326

Net G&A expense increased 14% on an absolute-dollar basis and 30% on a per-BOE basis between the first quarter of 2012 and the first quarter of 2013.

Gross administrative costs increased $9.9 million, or 13%, during the three months ended March 31, 2013 compared to the same period in 2012. The increase between the comparative three-month periods was primarily due to higher compensation-related costs from an increase in headcount (11%), higher salaries due to annual merit increases, higher 401(k) match expense due to a higher bonus payout during the first quarter of 2013, and an increase in the mix of long-term incentive compensation to include more cash-based awards in lieu of stock-based awards.

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. In addition, salaries associated with field personnel are initially recorded as gross administrative costs and subsequently reclassified to lease operating expenses or capitalized to field development costs to the extent those individuals are dedicated to oil and gas production, exploration, and development activities. 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 8% during the three months ended March 31, 2013 compared to the amounts recovered in the same period in 2012. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

Table of Contents
Denbury Resources Inc.
Management’s Discussion and Analysis of Financial Condition and Results of Operations

Interest and Financing Expenses

In thousands, except per-BOE data and interest rates	Three Months Ended March 31, 2013	2012
Cash interest expense	$54,002	$52,033
Noncash interest expense	3,737	3,726
Less: Capitalized interest	(21,705)	(19,445)
Interest expense, net	$36,034	$36,314
Interest expense, net per BOE	$6.27	$5.59
Average debt outstanding	$3,229,289	$2,744,926
Average interest rate (1)	6.7%	7.6%

(1) Includes commitment fees but excludes debt issue costs and amortization of discount or premium.

Interest expense, net decreased 1% between the three months ended March 31, 2013 compared to the same period in 2012. The slight decrease in interest expense is largely due to higher capitalized interest, offset in part by higher cash interest expense resulting from an increase in average debt outstanding during the period. The decrease in the average interest rate is a result of the refinancing of our 9½% Notes and 9¾% Notes with our 2023 Notes, which carry a rate of 4 5/8% (see Overview – Debt Refinancing above). The increase in capitalized interest between the three months ended March 31, 2012 and 2013 relates primarily to incremental capitalized interest on construction projects, as well as capitalized interest on EOR development projects.

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

In thousands, except per-BOE data	Three Months Ended March 31, 2013	2012
Depletion and depreciation of oil and natural gas properties	$85,179	$107,055
Depletion and depreciation of CO_2 properties	7,337	5,110
Asset retirement obligations	2,104	1,695
Depreciation of other fixed assets	18,278	7,035
Total DD&A	$112,898	$120,895
DD&A per BOE:		
Oil and natural gas properties	$15.20	$16.71
CO_2 and other fixed assets	4.45	1.86
Total DD&A cost per BOE	$19.65	$18.57

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs. In addition, under full cost accounting rules, the divestiture of oil and gas properties generally does not result in gain or loss recognition; instead, the proceeds of the disposition reduce the full cost pool. As such, our DD&A rate has changed significantly over time, and it may continue to change in the future. Depletion and depreciation of oil and natural gas properties decreased between the first quarters of 2012 and 2013 on both an absolute-dollar basis and a per-BOE basis. During the first quarter of 2013, our DD&A rate for oil and gas properties was $15.20 per BOE, which was lower than first quarter 2012 levels due to the exchange of our Bakken area assets for other property interests in late 2012. As a result of this exchange, there was a net decrease in costs subject to depletion, partially offset by a reduction in total proved reserves. The decrease in the DD&A rate due to the Bakken exchange transaction was partially offset by the impact of the CCA acquisition in March 2013. Our DD&A rate per BOE increased from the fourth quarter of 2012 rate of $14.39 due to the acquisition of CCA during the first quarter of 2013.

Table of Contents
Denbury Resources Inc.
Management's Discussion and Analysis of Financial Condition and Results of Operations

Depletion and depreciation of our CO_2 and other fixed assets increased on an absolute-dollar basis during the first quarter of 2013 compared to that during the same period in 2012 primarily due to the change in classification of our equipment leases from operating to capital during the second quarter of 2012 and the higher rate per BOE was impacted by both the higher expense and lower oil and natural gas production during the first quarter of 2013. See Note 5, Long-term Debt, of our 2012 Consolidated Financial Statements in the Form 10-K for further discussion of the change in classification of our equipment leases.

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 March 31, 2013; however, if oil or 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 $17.3 million of impairment charges during the three months ended March 31, 2012, primarily related to our investment in Faustina Hydrogen Products LLC, an entity created to develop a proposed plant from which we could offtake CO_2, as a result of the project not moving forward. See Note 6, Fair Value Measurements, to the Unaudited Condensed Consolidated Financial Statements.

Income Taxes

	Three Months Ended March 31,	
In thousands, except per-BOE amounts and tax rates	2013	2012
Current income tax expense	$10,519	$28,708
Deferred income tax expense	43,845	37,137
Total income tax expense	$54,364	$65,845
Average income tax expense per BOE	$9.46	$10.12
Effective tax rate	38.3 %	36.7 %

Our income taxes are based on an estimated statutory rate of approximately 38.5%. Our effective tax rate for the first quarter of 2013 was comparable to that estimated statutory rate; however, in the prior year quarter the effective rate was lower due to the utilization of a larger amount of preferential tax benefits due to the sale of an investment in that period. Current taxes made up a larger percentage of our overall taxes in the prior year quarter due to the gain on sale of our investment in Vanguard during that period.

As of March 31, 2013, we had an estimated $17.3 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 2013 or future years, but cannot be used to offset alternative minimum tax. The enhanced oil recovery credits do not begin to expire until 2025. 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.

Table of Contents
Denbury Resources Inc.
Management's Discussion and Analysis of Financial Condition and Results of Operations

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 March 31,	
Per-BOE data	2013	2012
Oil and natural gas revenues	$99.87	$97.32
Loss on settlements of derivative contracts	—	(0.18)
Lease operating expenses	(24.47)	(21.19)
Production and ad valorem taxes	(6.17)	(6.31)
Marketing expenses, net of third party purchases	(1.41)	(1.66)
Production netback	67.82	67.98
CO_2 sales, net of operating and exploration expenses	0.49	0.08
General and administrative expenses	(7.29)	(5.62)
Interest expense, net	(6.27)	(5.59)
Other	0.22	(2.75)
Changes in assets and liabilities relating to operations	(8.11)	(9.30)
Cash flow from operations	46.86	44.80
DD&A	(19.65)	(18.57)
Deferred income taxes	(7.63)	(5.71)
Loss on early extinguishment of debt	(7.70)	—
Noncash commodity derivative adjustments	(2.08)	(6.78)
Impairment of assets	—	(2.66)
Other noncash items	5.45	6.35
Net income	$15.25	$17.43

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.

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 Exchange Act of 1934, as amended (the "Exchange Act"), 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, pending or planned acquisitions or dispositions, development activities, timing of CO_2 injections and initial production responses thereto, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 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, the 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. These debt agreements expose us to market risk related to changes in interest rates. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease, in the event of significant downgrades of our corporate credit rating by the rating agencies, certain credit enhancements can be required from us, and possibly other remedies made available under the lease. As of March 31, 2013, our borrowings on our bank credit facility were $275.0 million, with a weighted average interest rate of 1.71%. 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 March 31, 2013:

In thousands	2014	2015	2016	2017	2020	2021	2023	Total
Variable rate debt:								
Bank Credit Facility (weighted average interest rate of 1.71% at March 31, 2013)	$—	$—	$275,000	$—	$—	$—	$—	$275,000
Fixed rate debt:								
9½% Senior Subordinated Notes due 2016	—	—	38,206	—	—	—	—	38,206
8¼% Senior Subordinated Notes due 2020	—	—	—	—	996,273	—	—	996,273
6 3/8% Senior Subordinated Notes due 2021	—	—	—	—	—	400,000	—	400,000
4 5/8% Senior Subordinated Notes due 2023							1,200,000	1,200,000
Other Subordinated Notes	1,072	485	—	2,250	—	—	—	3,807

Oil and Natural Gas Derivative Contracts

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 for approximately two years in the future from the current quarter, as we believe it is important to protect our future cash flow for a period of time in order to give us time to adjust to commodity price fluctuations, particularly since many of our planned expenditures have long lead times. Because our current and forecasted production is primarily oil (93% of volumes on a BOE-basis during the first quarter of 2013), we have focused primarily on oil derivative contracts in our commodity market risk management program. We may enter into natural gas derivative contracts in the future as the natural gas market improves and as we anticipate our natural gas production to increase with the expected start up of Riley Ridge gas production later this year. See Notes 5 and 6 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. All of our commodity derivative contracts are with parties that are lenders under our bank credit facility. 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 oil and natural gas 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.

At March 31, 2013, our derivative contracts were recorded at their fair value, which was a net liability of approximately $18.9 million, a $12.0 million increase from the $6.9 million net liability recorded at December 31, 2012. This change is primarily related to the expiration of oil derivative contracts during 2013 and to changes in oil futures prices between December 31, 2012 and March 31, 2013.

Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil futures prices as of March 31, 2013, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil derivative contracts as shown in the following table:

In thousands	Receipt/ (Payment)
Based on:	
NYMEX futures prices as of March 31, 2013	$—
10% increase in prices	(47,888)
10% decrease in prices	—

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 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 March 31, 2013, 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 our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the first quarter of fiscal 2013, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Information with respect to the risk factors has been incorporated by reference to 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 first quarter of 2013:

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 (in millions) (1)
January 2013	3,751,201	$16.74	3,533,133	$250.2
February 2013	19,052	18.66	—	250.2
March 2013	545,309	17.77	407,994	243.1
Total	4,315,562	16.88	3,941,127	243.1

(1) In October 2011, the Company's Board of Directors approved a share repurchase program for up to $500 million of Denbury's common stock, which was increased by an additional $271.2 million in early November 2012.

Between early October 2011, when we announced the commencement of a common share repurchase program and April 30, 2013, we repurchased 35.8 million shares of Denbury common stock (approximately 8.9% of our outstanding shares of common stock at September 30, 2011) for $541.9 million, or $15.13 per share. The program has no pre-established ending date and may be suspended or discontinued by our Board of Directors at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

All other repurchases of our common stock during the first quarter of 2013 were made 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.

Item 3. Defaults upon Senior Securities

None

Item 4. Mine Safety Disclosures

None

Item 5. Other Information

None

Table of Contents
Denbury Resources Inc.

Item 6. Exhibits

Exhibit No.	Exhibit
2(a)*	Closing Agreement and Amendment, dated March 27, 2013, between Burlington Resources Oil & Gas Company LP (a wholly-owned subsidiary of ConocoPhillips Company) and Denbury Onshore, LLC.
10(a)*	Form of 2013 Performance Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(b)*	Form of 2013 Performance Cash Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(c)*	Form of 2013 TSR Performance Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(d)*	Form of Restricted Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(e)*	Form of Stock Appreciation Rights Agreement under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
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.

*Included herewith.

Table of Contents
Denbury Resources Inc.

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.
May 10, 2013	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer
May 10, 2013	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer

Table of Contents
Denbury Resources Inc.

INDEX TO EXHIBITS

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101	Interactive Data Files.