ADVANCED ENERGY INDUSTRIES INC
Form 10-Q
April 30, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
For the quarterly period ended March 31, 2018
or
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: 000-26966
ADVANCED ENERGY INDUSTRIES, INC.
(Exact name of registrant as specified in its charter)

Delaware	84-0846841
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1625 Sharp Point Drive, Fort Collins, CO	80525
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (970) 221-4670

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 (§232.405 of this chapter) 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	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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

As of April 26, 2018 there were 39,329,426 shares of the registrant's Common Stock, par value $0.001 per share, outstanding.

ADVANCED ENERGY INDUSTRIES, INC.
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PART I FINANCIAL STATEMENTS
ITEM 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
ADVANCED ENERGY INDUSTRIES, INC.
Unaudited Condensed Consolidated Balance Sheets
(In thousands, except per share amounts)

	March 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$413,874	$407,283
Marketable securities	3,197	3,104
Accounts and other receivable, net of allowances of $1,824 and $1,748 respectively	116,900	87,429
Inventories	96,842	78,450
Income taxes receivable	2,226	1,295
Other current assets	7,895	8,129
Current assets from discontinued operations	9,638	9,535
Total current assets	650,572	595,225
Property and equipment, net	20,706	17,795
Deposits and other assets	4,207	3,051
Goodwill	54,906	53,812
Intangible assets, net	33,445	33,499
Deferred income tax assets	38,741	18,841
Non-current assets from discontinued operations	11,084	11,085
TOTAL ASSETS	$813,661	$733,308
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$61,328	$48,177
Income taxes payable	13,011	5,365
Accrued payroll and employee benefits	13,890	18,412
Other accrued expenses	21,395	19,913
Customer deposits	9,738	6,402
Current liabilities from discontinued operations	7,272	7,850
Total current liabilities	126,634	106,119
Deferred income tax liabilities	6,592	4,556
Uncertain tax positions	17,701	17,031
Long term deferred revenue	32,443	33,402
Other long-term liabilities	38,803	36,282
Non-current liabilities from discontinued operations	14,279	15,277
Total liabilities	236,452	212,667
Commitments and contingencies (Note 17)		
Stockholders' equity:		
Preferred stock, $0.001 par value, 1,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.001 par value, 70,000 shares authorized; 39,536 and 39,604 issued and outstanding, respectively	40	40
Additional paid-in capital	172,460	184,843
Accumulated other comprehensive income	4,837	2,533
Retained earnings	399,410	333,225
Advanced Energy stockholders' equity	576,747	520,641

Noncontrolling interest	462	—
Total stockholders’ equity	577,209	520,641
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$813,661	$733,308

The accompanying notes are an integral part of these Unaudited Condensed Consolidated Financial Statements.

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ADVANCED ENERGY INDUSTRIES, INC.
Unaudited Condensed Consolidated Statements of Operations
(In thousands, except per share amounts)

	Three Months Ended March 31,	
	2018	2017
Sales:		
Product	$171,209	$128,827
Services	24,408	20,524
Total sales	195,617	149,351
Cost of sales:		
Product	79,806	60,117
Services	12,166	10,403
Total cost of sales	91,972	
Retained earnings	2,652,386	2,434,835
Accumulated other comprehensive loss	(311)	(348)
Treasury stock, at cost, 35,642,949 and 30,601,262 shares, respectively	(542,891)	(456,465)
Total stockholders' equity	5,270,786	5,114,889
Total liabilities and stockholders' equity	$ 11,508,510	$ 11,139,342

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues and other income				
Oil, natural gas, and related product sales	$638,188	$592,141	$1,211,841	$1,225,642
CO_2 sales and transportation fees	6,562	5,301	13,120	12,096
Interest income and other income	5,334	4,339	8,209	9,159
Total revenues and other income	650,084	601,781	1,233,170	1,246,897
Expenses				
Lease operating expenses	220,558	124,511	361,100	262,475
Marketing expenses	13,332	12,218	23,128	23,048
CO_2 discovery and operating expenses	3,419	1,062	7,141	7,267
Taxes other than income	44,940	38,812	82,951	82,506
General and administrative expenses	33,382	34,826	75,271	71,433
Interest, net of amounts capitalized of $23,279, $18,475, $44,984, and $37,920, respectively	30,602	41,604	66,636	77,918
Depletion, depreciation, and amortization	126,907	132,289	239,805	253,184
Derivatives expense (income)	(45,501)	(139,109)	(33,572)	(93,834)
Loss on early extinguishment of debt	428	—	44,651	—
Impairment of assets	—	215	—	17,515
Other expenses	10,711	12,552	12,818	23,272
Total expenses	438,778	258,980	879,929	724,784
Income before income taxes	211,306	342,801	353,241	522,113
Income tax provision	81,326	130,936	135,690	196,781
Net income	$129,980	$211,865	$217,551	$325,332
Net income per common share – basic	$0.35	$0.55	$0.59	$0.84
Net income per common share – diluted	$0.35	$0.54	$0.58	$0.83
Weighted average common shares outstanding				
Basic	368,850	387,159	369,122	386,764
Diluted	371,969	390,702	372,417	390,823

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$129,980	$211,865	$217,551	$325,332
Other comprehensive income, net of income tax:				
Interest rate lock derivative contracts reclassified to income, net of tax of $11, $10, $19, and $21, respectively	17	17	37	35
Total other comprehensive income	17	17	37	35
Comprehensive income	$129,997	$211,882	$217,588	$325,367

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Six Months Ended June 30,	
	2013	2012
Cash flow from operating activities:		
Net income	$217,551	$325,332
Adjustments to reconcile net income to cash flow from operating activities:		
Depletion, depreciation, and amortization	239,805	253,184
Deferred income taxes	128,342	167,289
Stock-based compensation	15,671	15,249
Noncash fair value derivative adjustments	(33,516)	(87,686)
Loss on early extinguishment of debt	44,651	—
Amortization of debt issuance costs and discounts	7,139	7,347
Impairment of assets	—	17,515
Other, net	5,041	15,835
Changes in assets and liabilities, net of effects from acquisitions:		
Accrued production receivable	(6,769)	35,466
Trade and other receivables	3,117	(10,769)
Other current and long-term assets	(9,171)	6,851
Accounts payable and accrued liabilities	86,969	28,256
Oil and natural gas production payable	20,222	(7,985)
Other liabilities	(12,308)	(33,264)
Net cash provided by operating activities	706,744	732,620
Cash flow used in investing activities:		
Oil and natural gas capital expenditures	(486,163)	(574,008)
Acquisitions of oil and natural gas properties	(307)	(154,366)
CO_2 capital expenditures	(44,708)	(53,313)
Pipelines and plants capital expenditures	(97,480)	(169,675)
Purchases of other assets	(22,825)	(10,748)
Net proceeds from sales of oil and natural gas properties and equipment	5,496	32,302
Proceeds from sale of short-term investments	—	83,545
Other	(19,586)	(2,961)
Net cash used in investing activities	(665,573)	(849,224)
Cash flow provided by (used in) financing activities:		
Bank repayments	(970,000)	(400,000)
Bank borrowings	530,000	535,000
Repayment of senior subordinated notes	(651,270)	—
Premium paid on repayment of senior subordinated notes	(36,475)	—
Proceeds from issuance of senior subordinated notes	1,200,000	—
Costs of debt financing	(20,026)	(11)
Common stock repurchase program	(100,423)	—
Other	(15,623)	(8,965)
Net cash provided by (used in) financing activities	(63,817)	126,024
Net increase (decrease) in cash and cash equivalents	(22,646)	9,420
Cash and cash equivalents at beginning of period	98,511	18,693
Cash and cash equivalents at end of period	$75,865	$28,113

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is a growing independent oil and natural gas company. We are the largest combined oil and natural gas producer in both Mississippi and Montana, own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of our acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with 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 June 30, 2013, our consolidated results of operations for the three and six months ended June 30, 2013 and 2012, and our consolidated cash flows for the six months ended June 30, 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 and six months ended June 30, 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 outstanding used in the basic and diluted net income per common share calculations for the periods indicated:

In thousands	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Basic weighted average common shares outstanding	368,850	387,159	369,122	386,764
Potentially dilutive securities:				
Restricted stock, stock options, SARs and performance-based equity awards	3,119	3,543	3,295	4,059
Diluted weighted average common shares outstanding	371,969	390,702	372,417	390,823

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Basic weighted average common shares excludes shares of nonvested restricted stock. 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 for the three and six months ended June 30, 2013, respectively, and 3.9 million and 3.5 million shares for the three and six months ended June 30, 2012, respectively, were not included in the computation of diluted net income per share as their effect would have been antidilutive.

Recent Accounting Pronouncements

Balance Sheet Offsetting. In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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 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. The $1.05 billion placed in qualifying trust accounts 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 further evaluation of the oil and natural gas properties, other assets and related asset retirement obligations.

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.

For the three months ended June 30, 2013 and for the period from March 27, 2013 to June 30, 2013, we recognized $88.7 million and $92.7 million of oil, natural gas, and related product sales, respectively, from the property interests acquired in the CCA acquisition. For the three months ended June 30, 2013 and for the period from March 27, 2013 to June 30, 2013, we recognized $65.2 million and $67.9 million of net field operating income (oil, natural gas and related product sales less lease operating expenses and production and ad valorem taxes and marketing expenses), respectively, related to the CCA acquisition.

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 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 material adjustments were made during the first six months of 2013 to the preliminary fair value of the assets acquired and liabilities assumed 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. The field is located in close proximity to Hastings Field, which is an enhanced oil recovery field that we are currently flooding with CO_2 and which is the current terminus of the Green Pipeline which transports CO_2 both from the Jackson Dome area, located near Jackson, Mississippi, and from various anthropogenic sources. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is also a planned future tertiary field. 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.

This acquisition meets the definition of a business under the FASC Business Combinations topic. The fair values assigned to assets acquired and liabilities assumed in the June 2012 acquisition have been finalized and no adjustments have been made to fair value amounts previously disclosed in our Form 10-K for the period ended December 31, 2012.

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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 June 30,		Six Months Ended June 30,	
In thousands, except per share data	2013	2012	2013	2012
Pro forma total revenues and other income	$650,084	$640,996	$1,315,344	$1,327,045
Pro forma net income	129,980	234,621	245,571	368,152
Pro forma net income per common share				
Basic	$0.35	$0.61	$0.67	$0.95
Diluted	0.35	0.60	0.66	0.94

Other 2012 Divestitures. In April 2012, we completed the sale of certain non-operated assets in the Paradox Basin of Utah for $75.0 million. The sale had an effective date of January 1, 2012 and proceeds received after consideration of final closing adjustments totaled $68.5 million. 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. We did not record a gain or loss on these divestitures 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	June 30, 2013	December 31, 2012
Bank Credit Agreement	$260,000	$700,000
9½% Senior Subordinated Notes due 2016, including premium of $9,118	—	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 $21 and $25, respectively	3,828	3,832
Pipeline financings	231,626	236,244
Capital lease obligations	141,332	158,260
Total	3,233,059	3,141,428
Less: current obligations	(34,148)	(36,966)
Long-term debt and capital lease obligations	$3,198,911	$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

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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. The leverage ratio represents the ratio of total debt to EBITDA, both as defined within the 2023 Indenture.

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 a 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 loss associated with the debt repurchases of $0.4 million and $44.7 million during the three and six months ended June 30, 2013, respectively, consisting 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 these 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 1.7%

as of June 30, 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

Under our board-authorized share repurchase program, we repurchased 1.1 million shares of Denbury common stock for $19.0 million during the three months ended June 30, 2013 and 5.0 million shares of Denbury common stock for $85.2 million during the six months ended June 30, 2013. Since commencement of the share repurchase program in October 2011 through June 30, 2013, we have repurchased a total of 36.1 million shares of Denbury common stock for $547.1 million, or $15.15 per share. As of June 30, 2013, we had $224.1 million of remaining repurchases authorized under our 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 June 30,		Six Months Ended June 30,	
In thousands	2013	2012	2013	2012
Oil				
Cash payment on settlements of derivative contracts	$—	$709	$—	$8,939
Noncash fair value adjustments to derivative contracts – income	(45,501)	(140,923)	(33,572)	(98,478)
Total derivatives income – oil	(45,501)	(140,214)	(33,572)	(89,539)
Natural Gas				
Cash receipt on settlements of derivative contracts	—	(7,991)	—	(15,031)
	—	9,096	—	10,736

Noncash fair value adjustments to derivative contracts – expense				
Total derivatives expense (income) – natural gas	—	1,105	—	(4,295)
Derivatives expense (income)	$(45,501)	$(139,109)	$(33,572)	$(93,834)

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Commodity Derivative Contracts Not Classified as Hedging Instruments

The following table presents outstanding oil derivative contracts with respect to future production as of June 30, 2013:

					Contract Prices per Barrel of Oil		
		Type of	Pricing	Volume		Weighted Average Price	
Year	Months	Contract	Index	(Barrels per day)	Range	Floor	Ceiling
2013	July – Sept	Collar	NYMEX	56,000	$ 75.00 – 133.10	$79.64	$109.15
	Oct – Dec	Collar	NYMEX	54,000	80.00 – 127.50	80.00	117.53
2014	Jan – Mar	Collar	NYMEX	58,000	$ 80.00 – 104.50	$80.00	$102.11
	Apr – June	Collar	NYMEX	58,000	80.00 – 104.50	80.00	102.11
	July – Sept	Collar	NYMEX	58,000	80.00 – 100.00	80.00	97.73
	Oct – Dec	Collar	NYMEX	58,000	80.00 – 100.00	80.00	97.73
2015	Jan – Mar	Collar	NYMEX	38,000	$ 80.00 – 100.90	$80.00	$96.96
	Jan – Mar	Collar	LLS	20,000	85.00 – 104.00	85.00	101.45
	Apr – June	Collar	NYMEX	24,000	80.00 – 95.25	80.00	94.40
	Apr – June	Collar	LLS	20,000	85.00 – 103.00	85.00	102.01

Additional Disclosures about Derivative Instruments

At June 30, 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	June 30, 2013	December 31, 2012
		In thousands	
Derivative assets			
Crude oil contracts	Derivative assets – current	$9,915	$19,477
Crude oil contracts	Derivative assets – long-term	18,712	36
Derivative liabilities			
Crude oil contracts	Derivative liabilities – current	(1,895)	(2,659)
Deferred premiums	Derivative liabilities – current	—	(183)
Crude oil contracts	Derivative liabilities – long-term	(87)	(23,781)
Total derivatives not designated as hedging instruments		$26,645	$(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. As of June 30, 2013 all of our outstanding derivative contracts were 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 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.

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. At June 30, 2013, instruments in this category include non-exchange-traded oil collars that are based on regional pricing other than NYMEX (i.e., Louisiana Light Sweet). Our costless collars are valued using the Black-Scholes model, which is described above. We obtain and ensure the appropriateness of the significant inputs to the calculation, including contractual prices for the underlying instruments, maturity, forward prices for commodities, interest rates, volatility factors and credit worthiness, and the fair value estimate is prepared and reviewed on a quarterly basis. Implied volatilities utilized in the valuation of Level 3 instruments are developed using a benchmark, which is considered a significant unobservable input. A one percent increase or decrease in implied volatility would result in a change of approximately $0.3 million in the fair value of these instruments as of June 30, 2013.

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.

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

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
June 30, 2013				
Assets:				
Oil derivative contracts	$—	$25,444	$3,183	$28,627
Liabilities:				
Oil derivative contracts	—	(1,895)	(87)	(1,982)
Total	$—	$23,549	$3,096	$26,645
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 first quarter of 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 six months ended June 30, 2012. The inputs used to determine fair value of the investment included the projected future cash flows of the plant and risk-adjusted rate of return that we estimated would be used by a market participant in valuing the asset. These inputs are unobservable within the marketplace and therefore considered Level 3 within the fair value hierarchy. However, as there are currently no expected future cash flows associated with the plant, the preferred stock was determined to have no value.

Other Fair Value Measurements

The carrying value of our Bank Credit Facility approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods. 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 June 30, 2013 and December 31, 2012, excluding pipeline financing and capital lease obligations, was $2.855 billion and $2.957 billion, 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.

Delhi Field Release

In June 2013, a release of well fluids, consisting of a mixture of carbon dioxide, saltwater, natural gas and a small percentage of oil, was discovered and reported within the Denbury-operated Delhi Field located in northern Louisiana. Denbury immediately took remedial action to stop the release and contain and recover well fluids in the affected area. We continue to actively work with government and local officials and agencies to determine the best course of remediation. Currently, we believe the origin of the release to be one or more wells in the affected area of the field that had been previously plugged and abandoned. We currently estimate that we will incur a minimum of $70.0 million to stop the release and remediate the affected area. Accordingly, during the second quarter of 2013, we recorded $70.0 million of lease operating expense related to the release in our Unaudited Condensed Consolidated Statement of Operations and a corresponding liability classified as Accounts payable and accrued liabilities in our Unaudited Condensed Consolidated Balance Sheet. This estimate is based on costs incurred through July 31, 2013 of approximately $45.0 million, plus the Company's estimate of the minimum level of future costs based on our current understanding of the environmental impact of the release and methods available to remediate impacted properties. Since the area is still in the process of being remediated and final restoration plans have not yet been agreed upon with regulatory agencies, we are currently unable to reliably estimate the full extent of the costs that may ultimately be incurred by the Company related to this release. The Company maintains insurance coverage which we believe covers certain of the costs and damages related to the release, and we currently estimate that one-third to two-thirds of our minimum cost estimate may be recoverable under our insurance policies. However, we have not reached any agreement with our insurance carriers as to recoverable amounts, and given the uncertainties concerning our ultimate insurance recoveries, we have not recognized any such recoveries in our financial statements as of June 30, 2013. Insurance recoveries will be recognized in our financial statements during the period received or at the time receipt is determined to be virtually certain.

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 second quarter of 2013 was the first quarter that reflects the full operational impact of all of the assets we acquired as part of, or with the proceeds of, the Bakken area asset sale, which closed during the fourth quarter of 2012. These acquired assets include additional interests in the Cedar Creek Anticline ("CCA"), which we purchased late in the first quarter of 2013 (See Note 2, Acquisitions and Divestitures, to the Unaudited Condensed Consolidated Financial Statements for additional details surrounding the Bakken exchange transaction).

During the second quarter of 2013, we recognized net income of $130.0 million, or $0.35 per diluted common share, compared to net income of $211.9 million, or $0.54 per diluted common share, during the second quarter of 2012. Despite a $46.0 million increase in oil and natural gas revenues between the two periods, net income declined between the two periods primarily due to a decline of $86.3 million in pre-tax income related to the fair value change in our commodity derivative contracts between the two periods and a $96.0 million increase in lease operating expense in the most recent quarter, $70.0 million of which represents our estimate of the minimum costs to remediate the impacted area of Delhi Field subsequent to a release of well fluids in mid-June 2013. See Results of Operations – Operating Results Summary – Oil and Natural Gas Derivative Contracts and Delhi Field Release below for more information.

During the second quarter of 2013, our oil and natural gas production, which was 94% oil, increased 2%, from an average of 72,337 BOE/d produced during the second quarter of 2012 to an average of 74,052 BOE/d produced during the second quarter of 2013. The increase was due to an increase in tertiary production, together with the acquisition of additional interests in CCA and other non-tertiary production growth, primarily offset by the decline in production resulting from the divestiture of our Bakken area assets late in 2012. Our tertiary oil production averaged 38,752 Bbls/d during the second quarter of 2013, an increase of 10% over the 35,208 Bbls/d produced during the second quarter of 2012, but down slightly from our average tertiary production of 39,057 Bbls/d in the first quarter of 2013. 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 $98.92 per Bbl during the second quarter of 2013, compared to $95.63 per Bbl during the second quarter of 2012, but down from the $105.59 per Bbl average realized price in the first quarter of 2013. The actual oil price we realized relative to NYMEX oil prices (our NYMEX oil price differential) improved to $4.78 per Bbl above NYMEX prices in the second quarter of 2013, compared to a positive $2.14 per Bbl NYMEX differential in the second quarter of 2012, but was down from the $11.17 NYMEX differential in the first quarter of 2013. The improved oil price differential realized this quarter compared to the prior year is primarily due to the disposition of our Bakken area assets late in 2012, which production generally sold at a significant discount to NYMEX. 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, $1.05 billion of which 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 started injections at our Bell Creek Field in Montana during the second quarter of 2013, and our first tertiary oil production from this field commenced in July 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 our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes"), our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") and to pay down a portion of outstanding borrowings on our bank credit facility. During the three and six months ended June 30, 2013, we recognized a loss associated with the debt repurchases of $0.4 million and $44.7 million, respectively, 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.

Addition of Proved CO_2 Reserves. During the first six months of 2013, we added approximately 350 Bcf of estimated proved CO_2 reserves as a result of successful drilling in the Jackson Dome area, our primary source of CO_2 for the Gulf Coast region.

Evaluation of Means of Distributing Future Free Cash Flow to Stockholders. The Company is engaged in an internal analysis of its options for distributing the significant future levels of free cash flow we currently anticipate generating in 2017 and beyond to stockholders, along with whether and how we could accelerate any such cash distributions. In general, this analysis includes evaluation of different organizational structures, and the timing of development of future capital projects. The Company is targeting completion of this analysis and any accompanying decisions by its November 11, 2013 analyst meeting, and does not anticipate making any further announcement regarding this process prior to that time.

Delhi Field Release. In June 2013, a release of well fluids, consisting of a mixture of carbon dioxide, saltwater, natural gas and a small percentage of oil, was discovered and reported within the Denbury-operated Delhi Field located in northern Louisiana. Denbury immediately took remedial action to stop the release and contain and recover well fluids in the affected area. We continue to actively work with government and local officials and agencies to determine the best course of remediation. Currently, we believe the origin of the release to be one or more wells in the affected area of the field that had been previously plugged and abandoned. During the second quarter of 2013, we recorded $70.0 million of lease operating expense related to the release, which amount represents our current estimate of the minimum amount we expect to incur as a result of the release. Our estimate of these costs is preliminary and is based on a number of contingencies which have not been resolved, and the costs of which are not currently quantifiable. The Company maintains insurance coverage which we believe covers certain of the costs and damages related to the release, and we currently estimate that one-third to two-thirds of our minimum cost estimate may be recoverable under our insurance policies. However, we have not reached any agreement with our insurance carriers as to recoverable amounts, and given the uncertainties concerning our ultimate insurance recoveries, we have not recognized any such recoveries in our financial statements as of June 30, 2013. See Note 7, Commitments and Contingencies to the Unaudited Condensed Consolidated Financial Statements for further discussion.

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CAPITAL RESOURCES AND LIQUIDITY

2013 Capital Spending. We currently expect that our 2013 capital budget will be $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 startup costs associated with new tertiary floods. 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 startup costs associated with new tertiary floods.

During the six months ended June 30, 2013, we incurred capital expenditures of approximately $540.9 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 August 2013 and our current production forecast, at this time we anticipate that our 2013 cash flow from operations should be more than 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 through mid-2015 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 source of capital is our cash flow from operations. We use our bank credit facility as needed for acquisitions and to bridge the relatively minor timing differences between our cash flow and capital expenditure program. 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 June 30, 2013, we had $1.3 billion of unused availability under our bank credit facility and cash of $75.9 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, under which we have purchased a total of 36.1 million shares of Denbury common stock for $547.1 million, or an average of $15.15 per share, between commencement of the share repurchase program in October 2011 and June 30, 2013. As of June 30, 2013, we have $224.1 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 six months ended June 30, 2013 and 2012:

	Six Months Ended June 30,	
In thousands	2013	2012
Capital expenditures by project:		
Tertiary oil fields	$319,698	$246,633
CO_2 pipelines	20,767	83,115
CO_2 sources [(1)]	75,497	132,096
Other areas	124,931	305,535
Capital expenditures before acquisitions and capitalized interest	540,893	767,379
Less: recoveries from sale/leaseback transactions	—	(33,131)
Net capital expenditures excluding acquisitions and capitalized interest	540,893	734,248
Property acquisitions [(2)]	1,067,559	367,929
Capitalized interest	44,984	37,920
Capital expenditures, net of sale/leaseback transactions	$1,653,436	$1,140,097

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

(2) Property acquisitions during the six months ended June 30, 2013 include capital expenditures of approximately $1.1 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.

For the first six months of 2013, our capital expenditures other than those for property acquisitions were funded with $706.7 million of cash flow from operations, and those for property acquisitions were funded with proceeds from the Bakken exchange transaction. Our capital expenditures for the first six months of 2012 were funded with $732.6 million of cash flow from operations, $210.3 million of net proceeds (after final closing adjustments) from non-core oil and natural gas divestitures, $83.5 million of proceeds from the sale of our investment in Vanguard common units and the remainder with borrowings under our bank credit facility.

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 our Form 10-K under Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments and Obligations, plus estimated obligations related to the Delhi Field release (many of which are contingent and cannot yet be quantified). See Note 7, Commitments and Contingencies, to the Unaudited Condensed Consolidated Financial Statements for further discussion.

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.

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Operating Results Summary

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share and unit data	2013	2012	2013	2012
Operating results				
Net income	$129,980	$211,865	$217,551	$325,332
Net income per common share – basic	0.35	0.55	0.59	0.84
Net income per common share – diluted	0.35	0.54	0.58	0.83
Net cash provided by operating activities	437,568	440,966	706,744	732,620
Average daily production volumes				
Bbls/d	69,895	67,476	64,764	67,167
Mcf/d	24,945	29,163	25,210	28,608
BOE/d (1)	74,052	72,337	68,966	71,934
Operating revenues				
Oil sales	$629,189	$587,191	$1,195,332	$1,210,897
Natural gas sales	8,999	4,950	16,509	14,745
Total oil and natural gas sales	$638,188	$592,141	$1,211,841	$1,225,642
Commodity derivative contracts (2)				
Cash receipt on settlements of derivative contracts	$—	$7,282	$—	$6,092
Noncash fair value adjustments to derivative contracts – income	45,501	131,827	33,572	87,742
Total income from commodity derivative contracts	$45,501	$139,109	$33,572	$93,834
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$98.92	$95.63	$101.97	$99.06
Natural gas price per Mcf	3.96	1.87	3.62	2.83
Unit prices – including impact of derivative settlements (2)				
Oil price per Bbl	$98.92	$95.51	$101.97	$98.33
Natural gas price per Mcf	3.96	4.88	3.62	5.72
Oil and natural gas operating expenses				
Lease operating expenses (3)	$220,558	$124,511	$361,100	$262,475
Marketing expenses	13,332	12,218	23,128	23,048
Production and ad valorem taxes	41,049	36,232	76,469	77,287
Oil and natural gas operating revenues and expenses per BOE (1)				
Oil and natural gas revenues	$94.70	$89.96	$97.08	$93.62
Lease operating expenses (3)	32.73	18.92	28.93	20.05
Marketing expenses, net of third-party purchases	1.55	1.26	1.47	1.46
Production and ad valorem taxes	6.09	5.50	6.13	5.90
CO_2 revenues and expenses				
CO_2 sales and transportation fees	$6,562	$5,301	$13,120	$12,096
CO_2 discovery and operating expenses (4)	(3,419)	(1,062)	(7,141)	(7,267)
CO_2 revenue and expenses, net	$3,143	$4,239	$5,979	$4,829

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

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

(3) Excluding estimated lease operating expense recorded during the second quarter of 2013 to remediate an area of Delhi Field (see Overview – Delhi Field Release above), lease operating expenses totaled $150.6 million and $291.1 million for the three and six months ended June 30, 2013, respectively and lease operating expense per BOE averaged $22.34 and $23.32 for the three and six months ended June 30, 2013, respectively.

(4) Includes $0.5 million of exploratory costs during the three and six months ended June 30, 2013 and $4.8 million during the six months ended June 30, 2012. We incurred no exploratory costs during the three months ended June 30, 2012.

Production

Average daily production by area for each of the four quarters of 2012 and for the first and second quarters 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	Second Quarter 2013
Tertiary oil production						
Gulf Coast region						
Mature properties:						
Brookhaven	3,014	2,779	2,460	2,520	2,305	2,339
Eucutta	3,090	2,870	2,782	2,730	2,636	2,642
Mallalieu	2,585	2,461	2,181	2,127	2,116	2,157
Other mature properties (1)	8,012	7,867	7,347	7,605	7,800	7,233
Delhi	4,181	4,023	3,813	5,237	5,827	5,479
Hastings	618	1,913	2,794	3,409	3,956	4,010
Heidelberg	3,583	3,823	3,716	3,930	3,943	4,149
Oyster Bayou	877	1,304	1,540	1,826	2,252	2,518
Tinsley	7,297	8,168	8,153	8,166	8,222	8,225
Total tertiary oil production	33,257	35,208	34,786	37,550	39,057	38,752
Non-tertiary oil and gas production						
Gulf Coast region						
Mississippi	4,573	4,095	3,401	3,663	3,013	2,367
Texas	3,674	4,573	5,173	5,513	6,692	6,932
Other	1,281	1,306	1,137	1,217	1,153	1,108
Total Gulf Coast region	9,528	9,974	9,711	10,393	10,858	10,407
Rocky Mountain region						
Cedar Creek Anticline (2)	8,496	8,535	8,490	8,493	8,745	19,935
Other	3,204	3,060	3,037	3,616	5,163	4,958
Total Rocky Mountain region	11,700	11,595	11,527	12,109	13,908	24,893
Total non-tertiary production	21,228	21,569	21,238	22,502	24,766	35,300
Total continuing production	54,485	56,777	56,024	60,052	63,823	74,052
Properties disposed:						
Bakken area assets (3)	15,285	15,503	16,752	10,064	—	—
2012 Non-core asset divestitures (4)	1,762	57	—	—	—	—

Total production	71,532	72,337	72,776	70,116	63,823	74,052

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(1) Other mature properties include Cranfield, Little Creek, Lockhart Crossing, Martinville, McComb and Soso fields.
(2) Beginning March 27, 2013, amounts include production from our purchase of additional interests in the CCA.
(3) Includes production from certain Bakken area assets sold in the fourth quarter of 2012.
(4) 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

Total production increased 1,715 BOE/d (2%) between the second quarters of 2012 and 2013, with the most recent quarter including production from CCA assets acquired in late March 2013, while the 2012 quarter included production from our Bakken area assets sold in December 2012 and other non-core assets sold during 2012. The most recent quarter's production levels reflect a return to production levels close to those prior to our fourth quarter 2012 Bakken sale and exchange. On a year-to-date basis, total production decreased 2,968 BOE/d (4%) between the first six months of 2012 and 2013, due primarily to the timing of the acquisition of CCA and the divestiture of Bakken area assets noted above. Our production during the three and six months ended June 30, 2013 was 94% oil, consistent with oil production of 93% during the three and six months ended June 30, 2012.

Continuing production, which includes production from recently acquired properties and excludes production related to properties sold or exchanged, increased 17,275 BOE/d (30%) during the three months ended June 30, 2013 over production levels in the 2012 comparable period, and increased from 55,631 BOE/d during the first six months of 2012 to 68,966 BOE/d during the first six months of 2013 (a 24% increase). Continuing production increases were primarily due to our acquisition of producing assets in the CCA which closed on March 27, 2013. Production from this acquisition contributed approximately 11,300 BOE/d to second quarter 2013 production and approximately 5,900 BOE/d to the first six months' average daily production total for 2013. Continuing production was also impacted by production increases from our tertiary oil fields and 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.

Tertiary Production

Oil production from our tertiary operations increased 10% when comparing the second quarters of 2013 and 2012, to 38,752 Bbls/d during the second quarter of 2013. This increase was 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, partially offset by normal declines in our mature tertiary fields. Sequentially, tertiary oil production during the second quarter of 2013 decreased 305 Bbls/d (1%) compared to production levels in the first quarter of 2013 primarily due to decreased production at Delhi Field and normal declines in our mature tertiary fields, offset by increased production primarily at Oyster Bayou and Heidelberg fields. Production at Delhi Field declined late in the second quarter of 2013 due to steps taken by the Company to stop the flow of well fluids in the field (see Overview – Delhi Field Release above) and production is expected to continue to decline until CO_2 injections to the impacted portion of the field (which were cut off in mid-June) resume. Based on our current analysis of the situation, we expect to resume CO_2 injections into the impacted area of the field in the fourth quarter of 2013. Once CO_2 injections resume, the field's oil production is anticipated to gradually recover. During July 2013, tertiary production at Delhi Field ranged from approximately 4,000 Bbls/d to 4,500 Bbls/d. Costs incurred as a result of the release, together with lower production levels, are currently expected to delay the effective date of a third party's reversionary interest in the Delhi Field until some time during 2014, which we previously estimated would decrease our share of production in Delhi Field by approximately 25% during the latter half of 2013.

Non-Tertiary Production

Continuing production from our non-tertiary operations increased to an average of 35,300 BOE/d during the second quarter of 2013, an increase of 13,731 BOE/d (64%) compared to second quarter 2012 non-tertiary continuing production levels and an increase of 10,534 BOE/d (43%) compared to first quarter of 2013 levels. The non-tertiary continuing production increases were primarily due to production from newly acquired fields, specifically CCA acquired in March 2013, Webster and Hartzog Draw fields acquired in the Bakken exchange transaction in late 2012 and Thompson Field acquired in June 2012. With the exception of the impact of production added from fields acquired during 2012 and 2013, 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.

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Oil and Natural Gas Revenues

Our oil and natural gas revenues increased 8% during the three months ended June 30, 2013 and decreased 1% during the six months ended June 30, 2013 compared to these revenues for the same periods in 2012. The increase during the three month period is related to increases in production and commodity prices, and the decrease during the six month period is related to a decrease in production, partially offset by an increase in commodity prices. The change in oil and natural gas revenues due to these factors, excluding any impact of our derivative contracts, is reflected in the following table:

In thousands	Three Months Ended June 30, 2013 vs. 2012 Increase in Revenues	Three Months Ended June 30, 2013 vs. 2012 Percentage Increase in Revenues	Six Months Ended June 30, 2013 vs. 2012 Increase (Decrease) in Revenues	Six Months Ended June 30, 2013 vs. 2012 Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Increase (decrease) in production	$14,046	2%	$(57,034)	(5)%
Increase in commodity prices	32,001	6%	43,233	4%
Total increase (decrease) in oil and natural gas revenues	$46,047	8%	$(13,801)	(1)%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first and second quarters and the six months ended June 30, 2013 and 2012:

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net realized prices:						
Oil price per Bbl	$105.59	$102.52	$98.92	$95.63	$101.97	$99.06
Natural gas price per Mcf	3.28	3.84	3.96	1.87	3.62	2.83
Price per BOE	99.87	97.32	94.70	89.96	97.08	93.62
NYMEX differentials:						
Oil per Bbl	$11.17	$(0.37)	$4.78	$2.14	$7.69	$0.87
Natural gas per Mcf	(0.21)	1.32	(0.05)	(0.49)	(0.14)	0.40

As reflected in the table above, our average net realized oil price increased 3% during the second quarter of 2013, compared to the average price received during the second quarter of 2012. Company-wide oil price differentials in the second quarter of 2013 were $4.78 per Bbl above NYMEX, compared to an average differential of $2.14 per Bbl above NYMEX in the second 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 and six months ended June 30, 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 $15.07 per Bbl on a trade-month basis for the second quarter of 2013, compared to a positive $18.14 per Bbl differential in the second quarter of 2012 and a positive $20.15 per Bbl in the first quarter of 2013. 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. The favorable LLS-to-NYMEX differential received in recent periods may not continue. In fact, during late July 2013, the LLS premium to NYMEX had decreased to around $6 positive to NYMEX.

NYMEX oil differentials in the Rocky Mountain region during the second quarter of 2013 were $6.77 per Bbl below NYMEX, compared to an average differential of $15.38 per Bbl below NYMEX in the second quarter of 2012 and $4.49 per Bbl below NYMEX in the first quarter of 2013. The change in the differential between 2012 and 2013 was largely impacted by the sale of our Bakken area assets in December 2012, as oil from the disposed properties sold at a significant discount to NYMEX during 2012, all due to increased production in the area coupled with limited transportation infrastructure.

During the second quarter of 2013, we sold approximately 44% of our crude oil at prices based on the LLS index price, approximately 22% 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.

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 and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,					
	2013	2012	2013	2012	2013	2012
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Cash settlement receipts (payments)	$—	$(709)	$—	$7,991	$—	$7,282
Noncash fair value gain (loss)	45,501	140,923	—	(9,096)	45,501	131,827
Total	$45,501	$140,214	$—	$(1,105)	$45,501	$139,109

	Six Months Ended June 30,					
	2013	2012	2013	2012	2013	2012
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Cash settlement receipts (payments)	$—	$(8,939)	$—	$15,031	$—	$6,092
Noncash fair value gain (loss)	33,572	98,478	—	(10,736)	33,572	87,742
Total	$33,572	$89,539	$—	$4,295	$33,572	$93,834

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 and LLS oil contracts given that our current and forecasted production is primarily oil (94% of volumes on a BOE-basis in the second quarter of 2013), leading us to focus at the current time solely 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 startup 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.

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Production Expenses

Lease operating expense

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data	2013	2012	2013	2012
Lease operating expense				
Tertiary	$152,941	$73,527	$239,749	$154,458
Non-tertiary	67,617	50,984	121,351	108,017
Total lease operating expense	$220,558	$124,511	$361,100	$262,475
Lease operating expense per BOE				
Tertiary (1)	$43.37	$22.95	$34.05	$24.79
Non-tertiary	21.05	15.09	22.30	15.74
Total lease operating expense per BOE (1)	32.73	18.92	28.93	20.05

(1) Excluding estimated lease operating expense recorded during the second quarter of 2013 to remediate an area of Delhi Field (see Overview – Delhi Field Release above), tertiary lease operating expenses per BOE averaged $23.52 and $24.11 for the three and six months ended June 30, 2013, respectively and total lease operating expense per BOE averaged $22.34 and $23.32 for the three and six months ended June 30, 2013, respectively.

Total lease operating expense during the three and six months ended June 30, 2013 increased from the comparable 2012 periods on an absolute-dollar and per-BOE basis primarily due to $70.0 million in estimated lease operating expenses recorded during the second quarter of 2013, which represents our current estimate of the minimum amount to remediate an area of Delhi Field impacted by a release of well fluids discovered in mid-June (see Overview – Delhi Field Release above). Excluding these estimated remediation expenses, lease operating expense increased $26.0 million and $28.6 million, respectively, during the three and six months ended June 30, 2013 compared to the same periods in 2012 due primarily to increased expenses resulting from our acquisition of additional interests in CCA late in the first quarter of 2013, expansion of our CO_2 floods, increased CO_2 expenses 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. Excluding the estimated Delhi Field remediation costs recorded during the second quarter of 2013, lease operating expense increased $3.42 and $3.27 per BOE for the three and six months ended June 30, 2013, respectively, compared to the comparable prior year periods. The increase in each period is primarily due to the sale of the Bakken assets in late 2012, which had a low operating cost per BOE, and the addition of Hartzog Draw and Webster fields, and additional interests in the CCA, which have a higher operating cost per BOE than the Bakken assets.

Tertiary lease operating expense increased $79.4 million and $85.3 million during the three and six months ended June 30, 2013 compared to those in the same periods in 2012 due primarily to an accrual of $70.0 million for estimated minimum expenses we expect to incur to remediate Delhi Field (see Overview – Delhi Field Release above). Excluding the estimated Delhi Field remediation expense, tertiary lease operating expense increased $9.4 million and $15.3 million, respectively, during the three and six months ended June 30, 2013 compared to the same periods in 2012. These increases were primarily a result of the expansion of our CO_2 floods and increased CO_2 expenses 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 second quarter of 2013, approximately 74% 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 for CO_2, our average cost of CO_2 for the Gulf Coast region during the second quarter of 2013 was approximately \$0.30 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 second quarter of 2013 was higher than the \$0.29 per Mcf spent during the second 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 \$0.40 per Mcf and \$0.36 per Mcf during the second quarter of 2013 and 2012, respectively.

Tertiary lease operating expense averaged \$43.37 and \$34.05 per Bbl during the three and six months ended June 30, 2013, respectively, compared to \$22.95 and \$24.79 per Bbl for the comparable prior-year period. The increase in tertiary operating costs per barrel in the second quarter of 2013 compared to the same period in 2012 is due primarily to the expense for estimated remediation costs at Delhi Field. Excluding the estimated Delhi remediation expense, tertiary operating expense averaged \$23.52 and \$24.11 per Bbl during the three and six months ended June 30, 2013, representing a 2% increase and 3% decrease per Bbl, respectively, compared to the same periods in 2012.

Non-tertiary lease operating expense increased 33% and 12% on an absolute-dollar basis during the three and six months ended June 30, 2013, respectively, compared to the same prior-year periods, as declines resulting from the sale of our Bakken area assets were more than offset by increases in newly acquired fields, including Thompson field acquired in June 2012, Webster and Hartzog Draw fields acquired in the Bakken exchange transaction in late 2012, and CCA acquired in March 2013. On a per-BOE basis, non-tertiary lease operating expense during the three and six months ended June 30, 2013 increased 39% and 42%, respectively, compared to the same prior-year periods due to increases in newly acquired fields, which have a higher operating cost per barrel.

Taxes other than income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income increased \$6.1 million and \$0.4 million during the three and six months ended June 30, 2013, respectively, compared to the same periods in 2012. The change in each period is generally aligned with fluctuations in oil and natural gas revenues. The increase during both comparative periods is further impacted by the change in the mix of properties subject to production and ad valorem taxes as a result of the Bakken exchange transaction and CCA acquisition.

General and Administrative Expenses ("G&A")

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data and employees	2013	2012	2013	2012
Gross administrative costs	$80,511	$71,739	$164,518	$145,798
Gross stock-based compensation	9,996	9,364	20,759	19,958
Operator labor and overhead recovery charges	(43,398)	(34,382)	(81,792)	(70,006)
Capitalized exploration and development costs	(13,727)	(11,895)	(28,214)	(24,317)
Net G&A expense	$33,382	$34,826	$75,271	$71,433
G&A per BOE:				
Net administrative costs	$3.89	$4.27	$4.88	$4.41
Net stock-based compensation	1.06	1.02	1.15	1.05
Net G&A expense	$4.95	$5.29	$6.03	$5.46
Employees as of June 30	1,544	1,414	1,544	1,414

Net G&A expense decreased 4% on an absolute-dollar basis and 6% on a per-BOE basis between the three months ended June 30, 2012 and June 30, 2013, and increased 5% on an absolute-dollar basis and 10% on a per-BOE basis between the six months ended June 30, 2012 and June 30, 2013.

Gross administrative costs increased $8.8 million (12%) and $18.7 million (13%) during the three and six months ended June 30, 2013, respectively, compared to the same periods in 2012. The increase between the comparative three- and six-month periods was primarily due to higher compensation-related costs driven primarily from an increase in headcount (9%) and annual merit increases.

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, increased compensation expense and an increase in the COPAS overhead rate, the amount we recovered as operator labor and overhead charges increased by 26% and 17% during the three and six months ended June 30, 2013, respectively, compared to the amounts recovered in the same periods in 2012. Capitalized exploration and development costs increased between the periods, primarily due to increased compensation costs subject to capitalization.

Interest and Financing Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data and interest rates	2013	2012	2013	2012
Cash interest expense	$50,478	$56,376	$104,480	$108,409
Noncash interest expense	3,403	3,703	7,140	7,429
Less: Capitalized interest	(23,279)	(18,475)	(44,984)	(37,920)
Interest expense, net	$30,602	$41,604	$66,636	$77,918
Interest expense, net per BOE	$4.54	$6.32	$5.34	$5.95
Average debt outstanding	$3,271,282	$2,964,121	$3,250,401	$2,854,523
Average interest rate (1)	6.2%	7.6%	6.4%	7.6%

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

Interest expense, net decreased 26% and 14% between the three and six months ended June 30, 2013, respectively, compared to the same periods in 2012. The decrease in interest expense is due to higher capitalized interest, a lower average interest rate, and decreased borrowings on our bank credit facility. The decrease in the average interest rate is a result of refinancing 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 and six months ended June 30, 2012 and 2013 relates primarily to incremental capitalized interest on construction projects, as well as capitalized interest on enhanced oil recovery development projects.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data	2013	2012	2013	2012
Depletion and depreciation of oil and natural gas properties	$99,927	$109,279	$185,106	$216,334
Depletion and depreciation of CO_2 properties	6,932	5,427	14,269	10,537
Asset retirement obligations	2,116	1,829	4,220	3,524
Depreciation of other fixed assets	17,932	15,754	36,210	22,789
Total DD&A	$126,907	$132,289	$239,805	$253,184
DD&A per BOE:				
Oil and natural gas properties	$15.14	$16.88	$15.16	$16.79
CO_2 and other fixed assets	3.68	3.22	4.04	2.55
Total DD&A cost per BOE	$18.82	$20.10	$19.20	$19.34

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 9% and 14% on an absolute-dollar basis for the three and six months ended June 30, 2013, respectively, and decreased 10% on a per-BOE basis during both the three and six months ended June 30, 2013, compared to the same periods in 2012. These decreases were primarily due to the sale and exchange of our Bakken area assets for other property interests in late 2012, partially offset by the impact of the CCA acquisition in March 2013. 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.

Depletion and depreciation of our CO_2 properties and other fixed assets increased on an absolute-dollar and per-BOE basis during the three and six months ended June 30, 2013 compared to the same periods in 2012 primarily due to an increase in CO_2 properties, pipelines and plants subject to depreciation as a result of continued development. The increase during the six months ended June 30, 2013 was further impacted by a change in classification of our equipment leases from operating to capital during the second quarter of 2012, and the amount on a per-BOE basis was also impacted by 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. On a sequential-quarter basis, second quarter of 2013 depletion of CO_2 properties decreased on an absolute-dollar basis from first quarter of 2013 levels due to an increase in CO_2 reserves during the current period as a result of successful drilling in the Jackson Dome area and decreased on a per-BOE basis primarily due to increased oil production during the second quarter of 2013.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have a ceiling test write-down at June 30, 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 $17.5 million of impairment charges during the six months ended June 30, 2012, primarily related to our investment in Faustina Hydrogen Products LLC, an entity created to develop a proposed plant from which we 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.

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Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE amounts and tax rates	2013	2012	2013	2012
Current income tax expense (benefit)	$(3,171)	$784	$7,348	$29,492
Deferred income tax expense	84,497	130,152	128,342	167,289
Total income tax expense	$81,326	$130,936	$135,690	$196,781
Average income tax expense per BOE	$12.07	$19.89	$10.87	$15.03
Effective tax rate	38.5%	38.2%	38.4%	37.7%

Our income taxes are based on estimated statutory rates of approximately 38.5% and 38% in 2013 and 2012, respectively. Our effective tax rate for the three months ended June 30, 2013 and 2012, and the six months ended June 30, 2013, was comparable to the estimated statutory rate; however, during the six months ended June 30, 2012, 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. The Company recorded a current income tax benefit during the second quarter of 2013 in recognition of an increase in its estimate of tax benefits expected to be received during 2013.

As of June 30, 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.

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Per-BOE Data

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Per-BOE data	2013	2012	2013	2012
Oil and natural gas revenues	$94.70	$89.96	$97.08	$93.62
Gain on settlements of derivative contracts	—	1.10	—	0.47
Lease operating expenses	(32.73)	(18.92)	(28.93)	(20.05)
Production and ad valorem taxes	(6.09)	(5.50)	(6.13)	(5.90)
Marketing expenses, net of third party purchases	(1.55)	(1.26)	(1.47)	(1.46)
Production netback	54.33	65.38	60.55	66.68
CO_2 sales, net of operating and exploration expenses	0.46	0.65	0.48	0.36
General and administrative expenses	(4.95)	(5.29)	(6.03)	(5.46)
Interest expense, net	(4.54)	(6.32)	(5.34)	(5.95)
Other	0.54	0.55	0.39	(1.10)
Changes in assets and liabilities relating to operations	19.09	12.02	6.57	1.42
Cash flow from operations	64.93	66.99	56.62	55.95
DD&A	(18.82)	(20.10)	(19.20)	(19.34)
Deferred income taxes	(12.54)	(19.77)	(10.28)	(12.78)
Loss on early extinguishment of debt	(0.06)	—	(3.58)	—
Noncash commodity derivative adjustments	6.75	20.03	2.69	6.70
Impairment of assets	—	(0.03)	—	(1.34)
Other noncash items	(20.97)	(14.93)	(8.82)	(4.34)
Net income	$19.29	$32.19	$17.43	$24.85

CRITICAL ACCOUNTING POLICIES

Environmental and Litigation Contingencies

The Company makes judgments and estimates in recording liabilities for contingencies such as environmental remediation or ongoing litigation. Liabilities are recorded when it is both probable that a loss has been incurred and such loss is reasonably estimable. Assessments of liabilities are based on information obtained from independent and in-house experts, loss experience in similar situations, actual costs incurred, and other case-by-case factors. Actual costs can vary from such estimates for a variety of reasons. The costs of environmental remediation or litigation can vary from estimates due to new developments regarding the facts and circumstances of each event, including in the case of environmental remediation, the timing of remediation, our understanding of the environmental impact, remediation methods available, and regulatory requirements, and in the case of litigation, differing interpretations of laws and facts and assessments of damages asserted and/or incurred.

Other Critical Accounting Policies

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

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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, estimates of the range of potential insurance recoveries, minimum estimates of costs of remedial activities, 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," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," " 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 and remediation costs; disruption of operations and damages from well damage, 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.

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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 June 30, 2013, our borrowings on our bank credit facility were $260.0 million, with a weighted average interest rate of 1.7%. At this level of variable-rate debt, an increase or decrease of 10% in interest rates would have an immaterial effect on our interest expense.

The following table presents the principal balances of our debt, by maturity date, as of June 30, 2013:

In thousands	2014	2015	2016	2017	2020	2021	2023	Total
Variable rate debt:								
Bank Credit Facility (weighted average interest rate of 1.7% at June 30, 2013)	$—	$—	$260,000	$—	$—	$—	$—	$260,000
Fixed rate debt:								
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

We regularly 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 (94% of volumes on a BOE-basis during the second quarter of 2013), we currently hold only 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 startup 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.

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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 June 30, 2013, our derivative contracts were recorded at their fair value, which was a net asset of approximately $26.6 million, a $33.5 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 June 30, 2013.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of June 30, 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:	
Futures prices as of June 30, 2013	$—
10% increase in prices	(15,955)
10% decrease in prices	22,271

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of June 30, 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 second 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.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Although not material to the Company's business or financial condition, the description herein of a fine to be paid to Mississippi environmental regulators is being provided under Instruction 5.C. of Item 103 of Regulation S-K pertaining to administrative proceedings arising under state environmental laws on discharge of materials into the environment which involve monetary sanctions in excess of $100,000: On June 20, 2013, the Company entered into an Agreed Order with the Mississippi Commission on Environmental Quality related to a notice of violation for a release of fluids at the Tinsley Field in the third quarter of 2011, under which order the Company agreed to pay a $662,500 fine as a civil penalty related to the release.

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 second 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)
April 2013	800,559	$17.40	790,874	$229.3
May 2013	321,731	17.54	301,353	224.1
June 2013	15,946	17.79	—	224.1
Total	1,138,236	17.45	1,092,227	224.1

(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 June 30, 2013, we repurchased 36.1 million shares of Denbury common stock (approximately 9.0% of our outstanding shares of common stock at September 30, 2011) for $547.1 million, or $15.15 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 second 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

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Item 5. Other Information

None

Item 6. Exhibits

Exhibit No.	Exhibit
10(a)	Denbury Resources Inc. Amended and Restated Employee Stock Purchase Plan, effective as of May 22, 2013 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 28, 2013, File No. 001-12935).
10(b)	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective as of May 22, 2013 (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on May 28, 2013, File No. 001-12935).
10(c)*	Form of Restricted Share Award for Non-Employee Directors under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(d)*	Form of Deferred Stock Unit Award (with respect to Deferred Long-Term Incentive Awards) for Non-Employee Directors under the Director Deferred Compensation Plan for Denbury Resources Inc.
10(e)*	Form of Deferred Stock Unit Award (with respect to Deferred Director Fees) for Non-Employee Directors under the Director Deferred Compensation 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.

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SIGNATURES

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

	DENBURY RESOURCES INC.
August 6, 2013	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer
August 6, 2013	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer

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INDEX TO EXHIBITS

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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.