DENBURY RESOURCES INC
Form 10-Q
November 07, 2014

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

FORM 10-Q
(Mark One)
þ Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2014
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: 001-12935

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

Delaware	20-0467835
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
5320 Legacy Drive, Plano, TX	75024
(Address of principal executive offices)	(Zip Code)
Registrant's telephone number, including area code:	(972) 673-2000

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

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

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

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

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

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

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

Class	Outstanding at October 31, 2014
Common Stock, $.001 par value	352,562,628

Denbury Resources Inc.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Denbury Resources Inc.

Unaudited Condensed Consolidated Balance Sheets

(In thousands, except par value and share data)

	September 30, 2014	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents	$19,436	$12,187
Accrued production receivable	261,482	262,047
Trade and other receivables, net	85,386	78,295
Derivative assets	29,862	5
Deferred tax assets	6,127	52,754
Other current assets	14,193	9,271
Total current assets	416,486	414,559
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	9,575,271	8,945,326
Unevaluated properties	856,184	780,481
CO_2 properties	1,148,626	1,117,167
Pipelines and plants	2,241,644	2,209,560
Other property and equipment	468,846	466,969
Less accumulated depletion, depreciation, amortization and impairment	(4,093,889)	(3,668,225)
Net property and equipment	10,196,682	9,851,278
Derivative assets	26,464	9,942
Goodwill	1,283,590	1,283,590
Other assets	216,831	229,368
Total assets	$12,140,053	$11,788,737
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$366,153	$410,543
Oil and gas production payable	157,452	174,677
Derivative liabilities	534	53,822
Current maturities of long-term debt	34,712	36,157
Total current liabilities	558,851	675,199
Long-term liabilities		
Long-term debt, net of current portion	3,560,214	3,260,625
Asset retirement obligations	122,584	119,888
Derivative liabilities	—	3,413
Deferred tax liabilities	2,521,670	2,399,294
Other liabilities	26,965	28,912
Total long-term liabilities	6,231,433	5,812,132
Commitments and contingencies (Note 7)		
Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	—	—
	411	409

Common stock, $.001 par value, 600,000,000 shares authorized; 411,367,190 and 409,215,573 shares issued, respectively		
Paid-in capital in excess of par	3,225,323	3,186,714
Retained earnings	3,050,743	2,844,432
Accumulated other comprehensive loss	(226)	(276)
Treasury stock, at cost, 58,842,321 and 46,710,896 shares, respectively	(926,482)	(729,873)
Total stockholders' equity	5,349,769	5,301,406
Total liabilities and stockholders' equity	$12,140,053	$11,788,737

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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues and other income				
Oil, natural gas, and related product sales	$622,005	$666,803	$1,902,880	$1,878,644
CO_2 and helium sales and transportation fees	11,378	6,739	33,961	19,859
Interest income and other income	4,274	11,293	14,680	19,502
Total revenues and other income	637,657	684,835	1,951,521	1,918,005
Expenses				
Lease operating expenses	155,198	180,967	488,827	542,067
Marketing and plant operating expenses	15,328	13,131	50,263	36,259
CO_2 and helium discovery and operating expenses	11,434	4,120	22,229	11,261
Taxes other than income	39,966	49,267	136,761	132,218
General and administrative expenses	40,366	35,969	123,011	111,240
Interest, net of amounts capitalized of $5,862, $19,768, $17,413, and $64,752, respectively	44,752	34,501	140,136	101,137
Depletion, depreciation, and amortization	146,560	125,595	435,854	365,400
Commodity derivatives expense (income)	(252,265)	80,446	(825)	46,874
Loss on early extinguishment of debt	—	—	113,908	44,651
Other expenses	—	1,474	—	14,292
Total expenses	201,339	525,470	1,510,164	1,405,399
Income before income taxes	436,318	159,365	441,357	512,606
Income tax provision	167,570	57,311	169,499	193,001
Net income	$268,748	$102,054	$271,858	$319,605
Net income per common share				
Basic	$0.77	$0.28	$0.78	$0.87
Diluted	$0.77	$0.28	$0.77	$0.86
Dividends per common share	$0.0625	$—	$0.1875	$—
Weighted average common shares outstanding				
Basic	348,454	366,088	348,993	368,101
Diluted	350,918	369,142	351,347	371,316

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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income	$268,748	$102,054	$271,858	$319,605
Other comprehensive income, net of income tax:				
Interest rate lock derivative contracts reclassified to income, net of tax of $11, $11, $35, and $30, respectively	18	17	50	54
Total other comprehensive income	18	17	50	54
Comprehensive income	$268,766	$102,071	$271,908	$319,659

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)

	Nine Months Ended September 30,	
	2014	2013
Cash flows from operating activities		
Net income	$271,858	$319,605
Adjustments to reconcile net income to cash flow from operating activities		
Depletion, depreciation, and amortization	435,854	365,400
Deferred income taxes	168,967	169,634
Stock-based compensation	26,104	23,774
Commodity derivatives expense (income)	(825)	46,874
Settlements of commodity derivatives	(102,255)	(662)
Loss on early extinguishment of debt	113,908	44,651
Amortization of debt issuance costs and discounts	10,433	10,581
Other, net	(5,037)	(3,486)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	565	(34,910)
Trade and other receivables	(6,885)	(756)
Other current and long-term assets	(370)	(1,199)
Accounts payable and accrued liabilities	(7,195)	52,672
Oil and natural gas production payable	(17,225)	31,111
Other liabilities	(2,800)	(11,080)
Net cash provided by operating activities	885,097	1,012,209
Cash flows from investing activities		
Oil and natural gas capital expenditures	(699,012)	(688,270)
CO_2 capital expenditures	(38,272)	(72,929)
Pipelines and plants capital expenditures	(47,521)	(136,654)
Purchases of other assets	(6,253)	(29,680)
Net proceeds from sales of oil and natural gas properties and equipment	3,011	6,312
Other	(876)	(30,482)
Net cash used in investing activities	(788,923)	(951,703)
Cash flows from financing activities		
Bank repayments	(1,827,000)	(1,170,000)
Bank borrowings	1,897,000	780,000
Repayment of senior subordinated notes	(997,345)	(651,270)
Premium paid on repayment of senior subordinated notes	(101,342)	(36,475)
Proceeds from issuance of senior subordinated notes	1,250,000	1,200,000
Costs of debt financing	(17,551)	(20,026)
Common stock repurchase program	(211,356)	(215,197)
Dividends paid	(65,241)	—
Other	(16,090)	(19,501)
Net cash used in financing activities	(88,925)	(132,469)
Net increase (decrease) in cash and cash equivalents	7,249	(71,963)
Cash and cash equivalents at beginning of period	12,187	98,511
Cash and cash equivalents at end of period	$19,436	$26,548

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Denbury Resources Inc.
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, dividend-paying, domestic oil and natural gas company. 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. 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 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, 2013 (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 September 30, 2014, our consolidated results of operations for the three and nine months ended September 30, 2014 and 2013, and our consolidated cash flows for the nine months ended September 30, 2014 and 2013.

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 the 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 equity awards. For the three and nine months ended September 30, 2014 and 2013, there were no adjustments to net income for purposes of calculating basic or diluted net income per common share.

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

In thousands	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Basic weighted average common shares outstanding	348,454	366,088	348,993	368,101
Potentially dilutive securities:				
Restricted stock, stock options, SARs and performance-based equity awards	2,464	3,054	2,354	3,215
Diluted weighted average common shares outstanding	350,918	369,142	351,347	371,316

Basic weighted average common shares exclude 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, stock options, and SARs are included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, the purchase price that the grantee will pay in the future for stock options, and any estimated future tax consequences recognized directly in equity. Stock options and SARs of 3.8 million and 4.0 million shares for the three and nine months ended September 30, 2014, respectively, and 3.6 million shares for the three and nine months ended September 30, 2013, could potentially dilute earnings per share in the future, but were excluded from the computation of diluted net income per share as their effect would have been antidilutive.

Recent Accounting Pronouncements

Revenue Recognition. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"). ASU 2014-09 amends the guidance for revenue recognition to replace numerous, industry-specific requirements. The core principle of the ASU is that an entity should recognize revenue for the transfer of goods or services equal to the amount that it expects to be entitled to receive for those goods or services. The ASU implements a five-step process for customer contract revenue recognition that focuses on transfer of control, as opposed to transfer of risk and rewards. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The amendments in this ASU are effective for reporting periods beginning after December 15, 2016, and early adoption is prohibited. Entities can transition to the standard either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. Management is currently assessing the impact the adoption of ASU 2014-09 will have on our consolidated financial statements.

Discontinued Operations. In April 2014, the FASB issued ASU 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity ("ASU 2014-08"). ASU 2014-08 amends the definition of a discontinued operation under the Discontinued Operations subtopic of the Financial Accounting Standards Board Codification ("FASC") and requires entities to disclose additional information about discontinued operations and disposal transactions that do not meet the discontinued operations criteria. ASU 2014-08 will be applied prospectively for disposals of components of an entity and businesses or nonprofit activities that meet the criteria to be classified as held for sale and occur within annual periods beginning on or after December 15, 2014, and interim periods within those years. The adoption of ASU 2014-08 is currently not expected to have a material effect on our consolidated financial statements.

Note 2. Acquisition of Cedar Creek Anticline Properties in 2013

On March 27, 2013, we acquired producing assets in the Cedar Creek Anticline ("CCA") of Montana and North Dakota from a wholly-owned subsidiary of ConocoPhillips Company for $1.0 billion after final closing adjustments. This acquisition was not reflected as an Investing Activity on our Unaudited Condensed Consolidated Statement of Cash Flows for the nine months ended September 30, 2013 due to the movement of the cash used to acquire these assets through a qualified intermediary to facilitate a like-kind-exchange treatment under federal income tax rules. 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 this 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, 2013.

For the three months ended September 30, 2013 and for the period from March 27, 2013 to September 30, 2013, we recognized $97.1 million and $189.8 million of oil, natural gas, and related product sales, respectively, from the property interests acquired in the CCA acquisition. For the three months ended September 30, 2013 and for the period from March 27, 2013 to September 30, 2013, we recognized $70.9 million and $138.8 million of net field operating income (defined as oil, natural gas and related product sales less lease operating expenses, production and ad valorem taxes, and marketing expenses), respectively, related to the CCA acquisition.

Unaudited Pro Forma Acquisition Information. The following pro forma total revenues and other income and pro forma net income are presented as if the CCA acquisition had occurred on January 1, 2013:

In thousands, except per share data	Nine Months Ended September 30, 2013
Pro forma total revenues and other income	$2,000,179
Pro forma net income	349,809
Pro forma net income per common share	
Basic	$0.95
Diluted	0.94

Note 3. Long-Term Debt

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

In thousands	September 30, 2014	December 31, 2013
Bank Credit Agreement	$410,000	$340,000
8¼% Senior Subordinated Notes due 2020	—	996,273
6 % Senior Subordinated Notes due 2021	400,000	400,000
5½% Senior Subordinated Notes due 2022	1,250,000	—
4 % Senior Subordinated Notes due 2023	1,200,000	1,200,000
Other Subordinated Notes, including premium of $13 and $16, respectively	2,747	3,823
Pipeline financings	222,585	228,167
Capital lease obligations	109,594	128,519
Total	3,594,926	3,296,782
Less: current obligations	(34,712)	(36,157)
Long-term debt and capital lease obligations	$3,560,214	$3,260,625

The ultimate parent company in our corporate structure, 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.

$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 semiannually on or around May 1 and November 1 of each year, and additionally upon requested special redeterminations. The borrowing base is adjusted at the lenders' discretion and is based in part upon external factors over which we have no control (including approval by the lenders party to the Bank Credit Agreement). If our outstanding credit under the Bank Credit Agreement exceeds the then effective borrowing base, we would be required to repay the excess amount over a period not to exceed four months. On April 15, 2014, we entered into the Twelfth Amendment to the Bank Credit Agreement to, among other modifications, increase the limit on the amount of Additional Permitted Subordinate Debt (as defined in the Bank Credit Agreement) that we may incur, as part of the April 2014 issuance of our $1.25 billion of 5½% Senior Subordinated Notes due 2022 (the "5½% Notes") (see 2014 Issuance of 5½% Senior Subordinated Notes due 2022 below) and the refinancing of our $996.3 million of 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes"). Our borrowing base was reaffirmed at $1.6 billion in connection with our last semiannual review completed in May 2014 pursuant to the terms of the Bank

Credit Agreement. Our next semiannual review is currently in process, through which we do not anticipate any reduction in our current borrowing base. The weighted average interest rate on borrowings outstanding as of September 30, 2014 under the Bank Credit Agreement was 1.9%. We incur a commitment fee of either 0.375% or 0.5%, based on the ratio of outstanding credit to the borrowing base, on the unused availability under the Bank Credit Agreement. Loans under the Bank Credit Agreement mature in May 2016.

2014 Issuance of 5½% Senior Subordinated Notes due 2022

On April 30, 2014, we issued $1.25 billion of 5½% Notes. The 5½% Notes, which bear interest at a rate of 5.5% per annum, were sold at 100% of the principal amount. The net proceeds, after issuance costs, of $1.23 billion were used to repurchase or redeem our outstanding 8¼% Notes, which were issued in 2010 (see 2014 Repurchase and Redemption of 8¼% Notes below), and to pay down a portion of outstanding borrowings under our Bank Credit Agreement.

The 5½% Notes mature on May 1, 2022, and interest is payable on May 1 and November 1 of each year, commencing November 1, 2014. We may redeem the 5½% Notes in whole or in part at our option beginning May 1, 2017, at the following redemption prices: 104.125% on or after May 1, 2017; 102.75% on or after May 1, 2018; 101.375% on or after May 1, 2019; and 100% on or after May 1, 2020. Prior to May 1, 2017, we may at our option redeem up to an aggregate of 35% of the principal amount of the 5½% Notes at a price of 105.5% with the proceeds of certain equity offerings. In addition, at any time prior to May 1, 2017, we may redeem 100% of the principal amount of the 5½% Notes at a price equal to 100% of the principal amounts plus a "make whole" premium and accrued and unpaid interest. The indenture is generally consistent with the indenture for our 4 % Senior Subordinated Notes due 2023 (the "4 % Notes") and contains certain restrictions on our ability and the ability of our restricted subsidiaries to (1) incur additional debt; (2) make investments; (3) create liens on our assets or the assets of our restricted subsidiaries; (4) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to the Company or other restricted subsidiaries; (5) engage in transactions with our affiliates; (6) transfer or sell assets or subsidiary stock; (7) consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries; and (8) make restricted payments (which includes paying dividends on our common stock or redeeming, repurchasing or retiring such stock or subordinated debt) unless certain leverage ratios are met.

2014 Repurchase and Redemption of 8¼% Notes

On April 30, 2014, we completed a cash tender offer for our 8¼% Notes and purchased a total of $815.2 million principal amount of these notes. We received sufficient consents in the solicitation to amend the indenture governing the 8¼% Notes by entering into a supplemental indenture, which eliminated most of the restrictive covenants and certain events of default. The purchase under this tender offer was funded by a portion of the proceeds from the sale of our 5½% Notes. On April 30, 2014, we issued a notice of redemption and fully funded the redemption of all of the remaining outstanding 8¼% Notes ($181.1 million principal amount) at an amount equal to 100% of their principal amount plus the required make-whole premium and accrued interest up to but excluding the May 30, 2014 redemption date, resulting in a satisfaction and discharge of the indenture for the 8¼% Notes.

We recognized a $113.9 million loss associated with the debt repurchases during the second quarter of 2014, which loss consists of both premium payments made to repurchase or redeem the 8¼% Notes and the elimination of unamortized debt issuance costs 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," and premium payments made to repurchase the notes are classified as a financing cash outflow on our Unaudited Condensed Consolidated Statements of Cash Flows under the caption "Premium paid on repayment of senior subordinated notes."

2013 Issuance of 4 % Senior Subordinated Notes due 2023

In February 2013, we issued $1.2 billion of 4 % Notes. The 4 % Notes, which bear interest at a rate of 4.625% per annum, were sold at 100% of the principal amount. The net proceeds, after issuance costs, of $1.18 billion were used to repurchase or redeem our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes") and our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") (see 2013 Repurchase and Redemption of 9½% Notes and 9¾% Notes below) and to pay down a portion of outstanding borrowings under our Bank Credit Agreement.

2013 Repurchase and Redemption of 9½% Notes and 9¾% Notes

Pursuant to cash tender offers, we repurchased $426.4 million principal amount of our 9¾% Notes and $186.7 million principal amount of our 9½% Notes during the first quarter of 2013, and repurchased the remaining $38.2 million principal amount of our 9½% Notes during the second quarter of 2013. We recognized a loss associated with the debt repurchases of $44.7 million during the nine months ended September 30, 2013, consisting of both premium payments made to repurchase or redeem the 9½% Notes and 9¾% 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," and premium payments made to repurchase the notes are classified as a financing cash outflow on our Unaudited Condensed Consolidated Statements of Cash Flows under the caption "Premium paid on repayment of senior subordinated notes."

Note 4. Stockholders' Equity

Dividends

In each of the first three quarters of 2014, we paid a quarterly cash dividend to our common stockholders of $0.0625 per common share, with aggregate dividends of $65.2 million, or $0.1875 per common share, paid during the nine months ended September 30, 2014. See Note 8, Subsequent Event, for details regarding the dividend declared and to be paid in the fourth quarter of 2014.

Stock Repurchase Program

Under our board-authorized share repurchase program, we repurchased 12.4 million shares of Denbury common stock for $200.4 million during the first quarter of 2014. Since commencement of the share repurchase program in October 2011 through September 30, 2014, we have repurchased a total of 60.0 million shares of Denbury common stock for $940.0 million, or $15.68 per share. As of September 30, 2014, we were authorized to repurchase an additional $221.9 million of common stock under this repurchase program.

Note 5. Commodity 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 "Commodity 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, three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. 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 18 months to two years in the future from the current quarter, at prices supporting our long-range plan, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending and dividends in those future periods in light of current worldwide economic uncertainties and commodity price volatility.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification, and all of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement. As of September 30, 2014, 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.

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Notes to Unaudited Condensed Consolidated Financial Statements

The following table summarizes our commodity derivative contracts as of September 30, 2014, none of which are classified as hedging instruments in accordance with the FASC Derivatives and Hedging topic:

Months	Index Price	Volume (2)	Contract Prices (1) Range (3)		Weighted Average Price Swap	Sold Put	Floor	Ceiling
Oil Contracts:								
2014 Fixed-Price Swaps								
Oct – Dec	NYMEX	58,000	$ 90.00	– 93.50	$92.52	$—	$—	$—
2015 Enhanced Swaps (4)								
Jan – Mar	NYMEX	14,000	$ 90.00	– 90.30	$90.06	$65.21	$—	$—
Jan – Mar	LLS	16,000	93.20	– 94.00	93.63	68.00	—	—
Apr – June	NYMEX	8,000	90.00	– 90.00	90.00	65.75	—	—
Apr – June	LLS	16,000	93.20	– 94.00	93.65	68.00	—	—
July – Sept	NYMEX	10,000	90.00	– 90.10	90.02	65.30	—	—
July – Sept	LLS	16,000	93.20	– 94.00	93.65	68.00	—	—
Oct – Dec	NYMEX	12,000	91.15	– 94.00	92.42	68.00	—	—
Oct – Dec	LLS	8,000	93.80	– 96.50	94.94	68.00	—	—
2015 Collars								
Jan – Mar	NYMEX	24,000	$ 80.00	– 100.90	$—	$—	$80.00	$96.75
Jan – Mar	LLS	4,000	85.00	– 102.20	—	—	85.00	102.10
Apr – June	NYMEX	30,000	80.00	– 95.25	—	—	80.00	94.72
Apr – June	LLS	4,000	85.00	– 102.50	—	—	85.00	101.75
July – Sept	NYMEX	28,000	80.00	– 95.25	—	—	80.00	95.05
July – Sept	LLS	4,000	85.00	– 100.00	—	—	85.00	99.50
2015 Three-Way Collars (5)								
Oct – Dec	NYMEX	10,000	$ 85.00	– 102.00	$—	$68.00	$85.00	$99.00
Oct – Dec	LLS	8,000	88.00	– 104.25	—	68.00	88.00	100.99
2016 Enhanced Swaps (4)								
Jan – Mar	NYMEX	12,000	$ 90.65	– 93.35	$92.43	$68.00	$—	$—
Jan – Mar	LLS	8,000	93.70	– 95.45	94.81	68.50	—	—
Apr – June	NYMEX	2,000	90.35	– 90.35	90.35	68.00	—	—
Apr – June	LLS	6,000	93.30	– 93.50	93.38	70.00	—	—
2016 Three-Way Collars (5)								
Jan – Mar	NYMEX	10,000	$ 85.00	– 101.25	$—	$68.00	$85.00	$99.85
Jan – Mar	LLS	6,000	88.00	– 103.15	—	68.00	88.00	102.10
Apr – June	NYMEX	2,000	85.00	– 95.50	—	68.00	85.00	95.50
Apr – June	LLS	2,000	88.00	– 98.25	—	70.00	88.00	98.25
Natural Gas Contracts:								
2014 Collars								
Oct – Dec	NYMEX	14,000	$ 4.00	– 4.47	$—	$—	$4.00	$4.45
2015 Collars								
Jan – Dec	NYMEX	8,000	$ 4.00	– 4.53	$—	$—	$4.00	$4.51

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

(2) Contract volumes are stated in Bbls/d and MMBtus/d for oil and natural gas contracts, respectively.

(3) Ranges presented for fixed-price swaps and enhanced swaps represent the lowest and highest fixed prices of all open contracts for the period presented. For collars and three-way collars, ranges represent the lowest floor price and highest ceiling price for all open contracts for the period presented.

(4) An enhanced swap is a fixed-price swap contract combined with a sold put feature (at a lower price) with the same counterparty. The value associated with the sold put is used to increase or enhance the fixed price of the swap. At the contract settlement date, (1) if the index price is higher than the swap price, we pay the counterparty the difference between the index price and swap price for the contracted volumes, (2) if the index price is lower than the swap price but at or above the sold put price, the counterparty pays us the difference between the index price and the swap price for the contracted volumes, and (3) if the index price is lower than the sold put price, the counterparty pays us the difference between the swap price and the sold put price for the contracted volumes.

(5) A three-way collar is a costless collar contract combined with a sold put feature (at a lower price) with the same counterparty. The value received for the sold put is used to enhance the contracted floor and ceiling price of the related collar. At the contract settlement date, (1) if the index price is higher than the ceiling price, we pay the counterparty the difference between the index price and ceiling price for the contracted volumes, (2) if the index price is between the floor and ceiling price, no settlements occur, (3) if the index price is lower than the floor price but at or above the sold put price, the counterparty pays us the difference between the index price and the floor price for the contracted volumes, and (4) if the index price is lower than the sold put price, the counterparty pays us the difference between the floor price and the sold put price for the contracted volumes.

Note 6. Fair Value Measurements

The FASC Fair Value Measurement 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 income approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

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

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil and natural gas derivatives that are based on NYMEX pricing. Our fixed-price swap contracts are valued using a discounted cash flow model based upon forward commodity price curves. Our costless collars and the written put features of our enhanced oil swaps and three-way 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. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At September 30, 2014, instruments in this category include non-exchange-traded oil derivatives that are based on regional pricing other than NYMEX. The valuation models utilized for enhanced swaps, costless collars and three-way collars are consistent with the methodologies described above; however, since the instruments are based on regional pricing other than NYMEX, the inputs to the valuation are less observable. 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

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in implied volatility would result in a change of approximately $0.1 million in the fair value of these instruments as of September 30, 2014.

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

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

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
September 30, 2014				
Assets:				
Oil and natural gas derivative contracts – current	$—	$18,609	$11,253	$29,862
Oil and natural gas derivative contracts – long-term	—	15,422	11,042	26,464
Total Assets	$—	$34,031	$22,295	$56,326
Liabilities:				
Oil and natural gas derivative contracts – current	$—	$(534)	$—	$(534)
Oil and natural gas derivative contracts – long-term	—	—	—	—
Total Liabilities	$—	$(534)	$—	$(534)
December 31, 2013				
Assets:				
Oil and natural gas derivative contracts – current	$—	$5	$—	$5
Oil and natural gas derivative contracts – long-term	—	3,034	6,908	9,942
Total Assets	$—	$3,039	$6,908	$9,947
Liabilities:				
Oil and natural gas derivative contracts – current	$—	$(53,822)	$—	$(53,822)
Oil and natural gas derivative contracts – long-term	—	(3,214)	(199)	(3,413)
Total Liabilities	$—	$(57,036)	$(199)	$(57,235)

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

Level 3 Fair Value Measurements

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the three and nine months ended September 30, 2014 and 2013:

In thousands	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Fair value of Level 3 instruments, beginning of period	$(39,116)	$3,096	$6,709	$—
Fair value adjustments on commodity derivatives	61,411	(2,950)	15,586	146
Fair value of Level 3 instruments, end of period	$22,295	$146	$22,295	$146
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets or liabilities still held at the reporting date	$61,411	$(2,950)	$15,586	$146

We utilize an income approach to value our Level 3 enhanced swaps, costless collars and three-way collars. We obtain and ensure the appropriateness of the significant inputs to the calculations, 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. The following table details fair value inputs related to implied volatilities utilized in the valuation of our Level 3 oil derivative contracts:

	Fair Value at 9/30/2014 (in thousands)	Valuation Technique	Unobservable Input	Range
Oil derivative contracts	$22,295	Discounted cash flow / Black-Scholes	Volatility of Light Louisiana Sweet index for settlement periods beginning after January 1, 2015	14.7% – 23.8%

Other Fair Value Measurements

The carrying value of loans under our Bank Credit Agreement approximate fair value, as they are 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 long-term 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 September 30, 2014 and December 31, 2013, excluding pipeline financing and capital lease obligations, was $3,177.3 million and $2,956.8 million, respectively. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 7. Commitments and Contingencies

We are involved in various lawsuits, claims and other regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated. We are also subject to audits for various taxes (income, sales and use, and severance) 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 oil, was discovered (and reported) within an area of the Denbury-operated Delhi Field located in northern Louisiana. We completed our remediation efforts with respect to such release during the fourth quarter of 2013; however, we continue to monitor the impacted area to confirm the effectiveness of the remediation efforts. During the three months ended September 30, 2014, we recorded an additional $14.0 million of lease operating expenses related to this release and its remediation in our Unaudited Condensed Consolidated Statement of Operations, which brings our total cost estimate to date with respect to these expenses to $128.0 million, of which we have incurred $112.5 million. This quarter's $14.0 million of additional charges primarily consist of our actual or estimated expenses related to third-party property and commercial damage claims that have been asserted recently in connection with the release, which are expected to be recoverable under our insurance policies.

We maintain insurance policies to cover certain costs, damages and claims related to releases of well fluids and remediation. We received a $25.0 million cost reimbursement ($23.9 million net to Denbury) in October 2014 relative to the Delhi Field release and remediation from our insurance carrier providing the first layer of our excess insurance coverage, representing approximately 20% of our total incident costs of $128.0 million. Based on the probability of collection under our insurance policies as of September 30, 2014 and our receipt of the insurance reimbursement in October 2014, the insurance reimbursement was recognized as a reduction to lease operating expenses in our Unaudited Condensed Consolidated Statement of Operations for the three and nine months ended September 30, 2014. We have not reached any agreement with our remaining carriers as to further reimbursements. However, we continue to believe that under our policies we are entitled to reimbursement of certain costs estimated to range between approximately one-third and two-thirds of our total costs, and thus we are continuing to pursue further reimbursements. Any future insurance recoveries will be recognized in our financial statements during the period received or at the time such receipt and the amount thereof is determined to be virtually certain.

Note 8. Subsequent Event

Dividend Declaration

On October 28, 2014, the Board of Directors declared a dividend of $0.0625 per share on our common stock, payable on December 30, 2014, to stockholders of record at the close of business on November 25, 2014.

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, 2013 (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

Denbury is a growing, dividend-paying, domestic oil and natural gas company. 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. 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.

Oil Price Volatility. Although oil prices have historically been volatile, during the third quarter of 2014 and continuing in October 2014, oil prices dropped rapidly, with NYMEX prices ranging from $107 per Bbl late in the second quarter of 2014 to less than $80 per Bbl in early November 2014. Over the last five years, NYMEX oil prices have ranged between $68 per Bbl and $114 per Bbl. To provide greater certainty to the range of anticipated operating cash flows as we transitioned to a dividend-paying company, for 2014 we have utilized more fixed-price swaps in our commodity price hedging than in prior periods. Fixed-price swaps provide greater certainty of the price realized on oil sales, especially during periods of severe oil price fluctuations, as compared to other derivative instruments such as collars, which have a floor (minimum price realized) and ceiling price (maximum price realized) and thus expose us to commodity price risk as those prices approach either the floor or ceiling of the collar. For the fourth quarter of 2014, we have fixed-price swaps covering a substantial portion (58,000 Bbls/d, which amounts to approximately 80% of our oil production levels during the third quarter of 2014) of our anticipated oil production at a weighted average settlement price of $92.52. Based on our fourth quarter production forecast, and the pricing certainty these fixed-price swaps provide on a substantial portion of our remaining anticipated 2014 production, together with oil and natural gas commodity futures prices in early November 2014, we believe our 2014 cash flow from operations should be adequate to cover both our remaining 2014 capital budget and December 2014 dividend payments.

We have entered into a combination of enhanced swaps, collars, and three-way collars covering a total of 58,000 Bbls/d for the first three quarters of 2015 and 38,000 Bbls/d for the fourth quarter of 2015. Because roughly half of these 2015 derivative contracts are collars and three-way collars, the range of potential cash flows from operations in 2015 is wider than our 2014 range using fixed-price swaps. These 2015 collars and three-way collars, which include both NYMEX and LLS hedges, have a weighted average floor price of approximately $82 per Bbl (approximately $80 and $86 for NYMEX and LLS hedges, respectively) and a weighted average ceiling price of approximately $97 per Bbl (approximately $96 and $101 for NYMEX and LLS hedges, respectively). We generally intend to fund our capital expenditures and dividend payments with cash flows from operations, although there could be some incremental cash generated or borrowings required in any given year. At our annual analyst day in mid-November 2014, we will expand upon our 2015 plans, including our production and capital expenditure estimates and our planned dividend rate for 2015.

Operating Highlights. During the third quarter of 2014, we recognized net income of $268.7 million, or $0.77 per diluted common share, compared to net income of $102.1 million, or $0.28 per diluted common share, during the third quarter of 2013. The higher income between the comparative third quarters was principally due to the fluctuation in our commodity derivatives expense (income), as we realized income in the current period and expense in the prior-year period resulting in a $332.7 million (pretax) change between the two periods (principally due to a $357.0 million noncash increase in the fair value of our derivatives). The higher income in the most recent period is further impacted by a $25.8 million (pretax) decrease in lease operating expenses, as the prior-year period included Delhi remediation charges of $28.0 million (pretax), compared to a net reduction of lease operating expenses of $9.9 million (pretax) in the current-year period due primarily to insurance recoveries related to the same remediation.

Partially offsetting these favorable items was a $44.8 million (pretax) decrease in oil, natural gas, and related product sales driven by an 11% decrease in our realized oil prices between the two periods.

During the third quarter of 2014, our oil and natural gas production, which was 96% oil, averaged 73,810 BOE/d compared to 71,531 BOE/d produced during the third quarter of 2013. This 3% increase in production is attributable to an 11% increase in our tertiary oil production, to a Company quarterly record of 41,627 Bbls/d, offset by a 5% decline in production from our non-tertiary properties.

Our average realized oil price per barrel during the third quarter of 2014, excluding the impact of commodity derivative contracts, decreased to $94.78 per Bbl compared to $105.91 per Bbl realized during the third quarter of 2013 and $100.04 per Bbl realized during the second quarter of 2014. The actual oil price we realized relative to NYMEX oil prices (our NYMEX oil price differential) was $2.53 per Bbl below NYMEX prices in the third quarter of 2014, compared to a negative $0.03 per Bbl NYMEX differential in the third quarter of 2013, and a negative $3.03 per Bbl NYMEX differential in the second quarter of 2014. This decline in our oil price differential in comparison to its level in the third quarter of 2013 was driven by a decrease in the Light Louisiana Sweet index premium and increase in the Rocky Mountain region discount relative to NYMEX oil prices.

As a result of rising oil prices throughout the first half of 2014, we paid $25.0 million on our crude oil fixed-price swap contracts that settled during the third quarter of 2014, lowering our realized oil price noted above by $3.86 per Bbl. Based on current futures prices as of November 3, 2014, and the fixed-price swaps that we have in place for the remainder of 2014, we currently expect that we will receive settlements from these contracts, the amount of which is dependent upon fluctuations in future NYMEX prices in relation to the fixed prices of our swaps, which have a weighted average settlement price of $92.52 per Bbl for the fourth quarter of 2014.

In recent years, and particularly during 2013, we have experienced gradually rising costs. As a result, one of our primary focuses in 2014 has been to reduce costs throughout the organization, through a number of internal initiatives underway. Our cost reduction initiatives have identified many cost-saving opportunities that have started to show up in our results and which we expect will continue to reduce expenses in the future. For example, excluding Delhi remediation costs and insurance reimbursements and unplanned Riley Ridge well workovers, our lease operating expense per BOE decreased each sequential quarter in 2014 and decreased a total of 12% between the fourth quarter of 2013 and the third quarter of 2014. Our goal is to continue to reduce both capital project costs and per-barrel operating costs in the future.

April 2014 Debt Refinancing. On April 30, 2014, we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022 (the "5½% Notes"). The net proceeds of $1.23 billion were used to repurchase and redeem our outstanding 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes"), which were issued in 2010, and to pay down approximately $150 million of outstanding borrowings on our bank credit facility. Also on April 30, 2014, we (1) completed a cash tender offer for our 8¼% Notes in which we purchased a total of $815.2 million principal amount of these notes; and (2) issued a notice of redemption and fully funded the redemption of all of the remaining outstanding 8¼% Notes ($181.1 million principal amount) at a price paid by the Trustee on the May 30, 2014 redemption date equal to 100% of their principal amount plus the required make-whole premium and accrued interest up to the redemption date. This refinancing reduces our interest on a principal balance equal to that of the 8¼% Notes by over $27 million per year; however, after factoring in the incremental subordinated debt we issued and the higher interest rate on subordinated debt versus bank debt, our net annual interest savings are estimated at approximately $17 million. Due to the refinancing, we recognized a loss on extinguishment of debt of $113.9 million (principally related to the tender or redemption premium on the 8¼% Notes repurchased) during the second quarter of 2014.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and availability for borrowings under our bank credit facility. Our business is capital intensive, and it is common for oil and natural gas companies our size to reinvest most or all of their cash flow into developing new assets. We generally attempt to balance our capital expenditures and dividends with cash flows from operations. During the nine months ended September 30, 2014, we spent a combined $828.8 million on capital expenditures and dividends while generating $885.1 million of cash flows from operations. Due in part to this surplus, we reduced the amount borrowed on our bank credit facility to $410.0 million as of September 30, 2014 from $445.0 million as of June 30, 2014.

We project that we will have more than adequate capital resources and liquidity for the foreseeable future because (1) we have significant borrowing capacity on our bank line; (2) we have oil hedges in place for a significant portion of our forecasted proven oil production through the first half of 2016 (see Note 5, Commodity Derivative Contracts, to the Unaudited Condensed Consolidated Financial Statements for further details regarding the prices and volumes of our commodity derivative contracts); (3) generally, we plan to fund both our projected capital expenditures and dividends with cash flow from operations, which means that our expected growth in production and cash flow will gradually reduce our leverage (assuming oil prices are relatively consistent with current levels); (4) we can significantly reduce our capital expenditures for extended periods of time if necessary, due to lower cash flows or share repurchases, and still maintain current production levels as a result of the unique characteristics of CO_2 EOR operations; and (5) the maturity dates of all but a minor amount of our senior subordinated notes extend eight years or more, including the new 5½% Notes issued in connection with the April 2014 debt refinancing (discussed above), and carry attractive fixed interest rates ranging between 4 % and 6 %.

2014 Capital Spending. We anticipate that our full-year 2014 capital budget, excluding any acquisitions, will be $1.0 billion, plus approximately $100 million in capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods. This combined 2014 capital expenditure amount of $1.1 billion, excluding acquisitions, is comprised of the following:

- $680 million allocated for tertiary oil field expenditures;
- $220 million allocated for other areas, primarily non-tertiary oil field expenditures;
- $60 million for pipeline construction;
- $40 million to be spent on CO_2 sources; and
- $100 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 nine months ended September 30, 2014, we incurred capital expenditures of $761.9 million, excluding acquisitions. See additional detail on our expenditures in the Capital Expenditure Summary below. Based on our current level of spending, our 2014 capital expenditures could be slightly below our total budget of $1.1 billion.

Based on our fourth quarter production forecast, and our fixed-price swaps which cover a substantial portion of our remaining anticipated 2014 production, together with oil and natural gas commodity futures prices in early November 2014, we believe our 2014 cash flow from operations should be adequate to cover both our 2014 capital budget and December 2014 dividend payments. If prices were to further decrease in a substantial way, or changes in operating results were to cause us to have a significant reduction in fourth quarter 2014 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 we elect to significantly reduce our capital spending, such a reduction could lower our future anticipated production levels. For 2014 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).

Stock Repurchase Program. Our Board of Directors has approved a common share repurchase program for up to $1.162 billion of Denbury common stock. As of November 7, 2014, we had spent $940.0 million to repurchase 60.0 million shares of our common stock under this program (approximately 14.9% of our outstanding shares at September 30, 2011), leaving us with $221.9 million available for future purchases. As of November 7, 2014 (the date of this filing), our most recent purchases under the plan occurred in January and February 2014, when we repurchased $200.4 million of our common stock, which we have funded with incremental borrowings and excess cash flow from operations. Our share repurchases are based on various parameters including, but not limited to, the price of our common stock, oil prices, free cash flow, our leverage or other funding sources available to us. Therefore, future repurchases may be at a level less than the remaining approved balance under the program, for which there is no set expiration date. We anticipate that any additional repurchases during the remainder of 2014 will be primarily funded with excess cash flow from operations, borrowings under our bank credit facility, or from a reduction in capital spending. See Note 4, Stockholders' Equity, to the Unaudited Condensed Consolidated Financial Statements for further discussion.

Dividends. In each of the first three quarters of 2014, we paid common stockholders a quarterly cash dividend of $0.0625 per common share, or aggregate dividends of $65.2 million, and our Board of Directors has declared a dividend of $0.0625 per share on our common stock for the fourth quarter, which results in an annual dividend rate of $0.25 per share for 2014. We currently expect this to result in total dividend payments of approximately $87 million to our stockholders in 2014. The declaration and payment of future dividends is at the discretion of our Board of Directors, and the amount thereof will depend on our results of operations, financial condition, capital requirements, level of indebtedness, and other factors deemed relevant by the Board of Directors.

Insurance Recoveries to Cover Costs of 2013 Delhi Field Release. We completed our remediation efforts related to the release of well fluids at the Denbury-operated Delhi Field during the fourth quarter of 2013. During the three months ended September 30, 2014, we recorded an additional $14.0 million of lease operating expenses related to this release and its remediation in our Unaudited Condensed Consolidated Statement of Operations, which brings our total cost estimate to date with respect to these expenses to $128.0 million, of which we have incurred $112.5 million. This quarter's $14.0 million of additional charges primarily consist of our actual or estimated expenses related to third-party property and commercial damage claims that have been asserted recently in connection with the release, which are expected to be recoverable under our insurance policies.

We maintain insurance policies to cover certain costs, damages and claims related to releases of well fluids and remediation. We received a $25.0 million cost reimbursement ($23.9 million net to Denbury) in October 2014 relative to the Delhi Field release and remediation from our insurance carrier providing the first layer of our excess insurance coverage, representing approximately 20% of our total incident costs of $128.0 million. Based on the probability of collection under our insurance policies as of September 30, 2014 and our receipt of the insurance reimbursement in October 2014, the insurance reimbursement was recognized as a reduction to lease operating expenses in our Unaudited Condensed Consolidated Statement of Operations for the three and nine months ended September 30, 2014. We have not reached any agreement with our remaining carriers as to further reimbursements. However, we continue to believe that under our policies we are entitled to reimbursement of certain costs estimated to range between approximately one-third and two-thirds of our total costs, and thus we are continuing to pursue further reimbursements. Any future insurance recoveries will be recognized in our financial statements during the period received or at the time such receipt and the amount thereof is determined to be virtually certain.

Bank Credit Facility. We have a $1.6 billion bank credit facility that is secured by substantially all of our oil and natural gas properties. Our borrowing base for our bank credit facility was reaffirmed at $1.6 billion in connection with our last semiannual review completed in May 2014. Our next semiannual review is currently in process, through which we do not anticipate any reduction in our current borrowing base and we believe, based on current commodity prices and our proved reserves, 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 September 30, 2014, we had availability of $1.2 billion with respect to such borrowing base, leaving us significant liquidity to fund capital expenditures and future dividends.

Capital Expenditure Summary. The following table of capital expenditures includes accrued capital for the nine months ended September 30, 2014 and 2013:

	Nine Months Ended September 30,	
In thousands	2014	2013
Capital expenditures by project		
Tertiary oil fields	$442,810	$428,373
Non-tertiary fields	186,708	136,796
Capitalized interest and internal costs (1)	67,437	89,200
Oil and natural gas capital expenditures	696,955	654,369
CO_2 pipelines	24,612	39,363
CO_2 sources (2)	37,502	114,240
CO_2 capitalized interest and other	2,831	35,200
Capital expenditures, before acquisitions	761,900	843,172
Property acquisitions (3)	1,683	1,062,607
Capital expenditures, total	$763,583	$1,905,779

(1) Includes capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods.
(2) Includes capital expenditures related to the Riley Ridge gas processing facility.
(3) Property acquisitions during the nine months ended September 30, 2013 include capital expenditures of approximately $1.1 billion related to acquisitions during that 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 to facilitate like-kind-exchange treatment under federal income tax rules.

For the first nine months of 2014, our capital expenditures were fully funded with cash flow from operations. For the first nine months of 2013, our capital expenditures, other than those for property acquisitions, were fully funded with cash flow from operations, and our property acquisitions were funded with proceeds from the 2012 Bakken exchange transaction.

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, 2013 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, together with those changes described in the April 2014 Debt Refinancing section above. 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 are our primary long-term 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 – Financial Overview of Tertiary Operations in our Form 10-K for further information regarding these matters.

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

Operating Results Table

Certain of our operating results and statistics for the comparative three and nine months ended September 30, 2014 and 2013 are included in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per share and unit data	2014	2013	2014	2013
Operating results				
Net income	$268,748	$102,054	$271,858	$319,605
Net income per common share – basic	0.77	0.28	0.78	0.87
Net income per common share – diluted	0.77	0.28	0.77	0.86
Net cash provided by operating activities	340,392	305,465	885,097	1,012,209
Average daily production volumes				
Bbls/d	70,619	67,705	70,504	65,755
Mcf/d	19,147	22,957	22,671	24,451
BOE/d (1)	73,810	71,531	74,283	69,830
Operating revenues				
Oil sales	$615,745	$659,674	$1,876,524	$1,855,006
Natural gas sales	6,260	7,129	26,356	23,638
Total oil and natural gas sales	$622,005	$666,803	$1,902,880	$1,878,644
Commodity derivative contracts (2)				
Payment on settlements of commodity derivatives	$(24,914)	$(662)	$(102,255)	$(662)
Noncash fair value adjustments on commodity derivatives (3)	277,179	(79,784)	103,080	(46,212)
Commodity derivatives income (expense)	$252,265	$(80,446)	$825	$(46,874)
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$94.78	$105.91	$97.49	$103.34
Natural gas price per Mcf	3.55	3.38	4.26	3.54
Unit prices – including impact of derivative settlements (2)				
Oil price per Bbl	$90.92	$105.80	$92.22	$103.30
Natural gas price per Mcf	3.61	3.38	4.13	3.54
Oil and natural gas operating expenses				
Lease operating expenses (4)	$155,198	$180,967	$488,827	$542,067
Marketing expenses, net of third-party purchases, and plant operating expenses	11,082	9,123	36,869	27,647
Production and ad valorem taxes	36,279	46,073	126,213	122,542
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$91.60	$101.32	$93.83	$98.55
Lease operating expenses (4)	22.86	27.50	24.10	28.43
Marketing expenses, net of third-party purchases, and plant operating expenses	1.63	1.39	1.82	1.45
Production and ad valorem taxes	5.34	7.00	6.22	6.43
CO_2 sources and helium – revenues and expenses				

CO_2 and helium sales and transportation fees	$11,378	$6,739	$33,961	$19,859
CO_2 and helium discovery and operating expenses	(11,434)	(4,120)	(22,229)	(11,261)
CO_2 and helium revenue and expenses, net	$(56)	$2,619	$11,732	$8,598

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

(2) See also Commodity Derivative Contracts below and Item 3. Quantitative and Qualitative Disclosures about Market Risk for information concerning our derivative transactions.

(3) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure and is different from "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations in that the noncash fair value adjustments on commodity derivatives represents only the net change between periods of the fair market values of commodity derivative positions, and excludes the impact of settlements on commodity derivatives during the period, which were payments on settlements of $24.9 million and $102.3 million for the three and nine months ended September 30, 2014, respectively, and payments on settlements of $0.7 million for the three and nine months ended September 30, 2013. We believe that noncash fair value adjustments on commodity derivatives is a useful supplemental disclosure to "Commodity derivatives expense (income)" in order to differentiate noncash fair market value adjustments from settlements on commodity derivatives during the period. This supplemental disclosure is widely used within the industry and by securities analysts, banks and credit rating agencies in calculating EBITDA and in adjusting net income to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations.

(4) If lease operating expenses and related insurance recoveries recorded to remediate an area of Delhi Field (see Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release above) were excluded, lease operating expenses would have totaled $165.1 million and $498.7 million for the three and nine months ended September 30, 2014, respectively, and $153.0 million and $444.1 million for the three and nine months ended September 30, 2013, respectively. Lease operating expense per BOE would have averaged $24.32 and $24.59 for the three and nine months ended September 30, 2014, respectively, and $23.24 and $23.29 for the three and nine months ended September 30, 2013, respectively.

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

Production

Average daily production by area for each of the four quarters of 2013 and for the first, second, and third quarters of 2014 is shown below:

	Average Daily Production (BOE/d)						
Operating Area	First Quarter 2013	Second Quarter 2013	Third Quarter 2013	Fourth Quarter 2013	First Quarter 2014	Second Quarter 2014	Third Quarter 2014
Tertiary oil production							
Gulf Coast region							
Mature properties:							
Brookhaven	2,305	2,339	2,224	2,026	1,877	1,818	1,767
Eucutta	2,636	2,642	2,504	2,280	2,181	2,150	2,224
Mallalieu	2,116	2,157	2,042	1,886	1,837	1,839	1,869
Other mature properties (1)	7,800	7,233	6,761	6,287	6,283	6,156	6,189
Total mature properties	14,857	14,371	13,531	12,479	12,178	11,963	12,049
Delhi	5,827	5,479	4,517	4,793	4,708	4,543	4,377
Hastings	3,956	4,010	3,699	4,270	4,618	4,759	4,917
Heidelberg	3,943	4,149	4,553	5,206	5,325	5,609	5,721
Oyster Bayou	2,252	2,518	3,213	3,869	4,055	4,415	4,605
Tinsley	8,222	8,225	7,951	7,809	8,430	8,518	8,310
Total Gulf Coast region	39,057	38,752	37,464	38,426	39,314	39,807	39,979
Rocky Mountain region							
Bell Creek	—	—	49	177	578	1,090	1,648
Total Rocky Mountain region	—	—	49	177	578	1,090	1,648
Total tertiary oil production	39,057	38,752	37,513	38,603	39,892	40,897	41,627
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	3,013	2,367	2,692	2,711	2,513	2,319	2,346
Texas	6,692	6,932	6,548	5,994	6,444	6,508	5,537
Other	1,153	1,108	1,087	1,041	1,031	1,049	1,083
Total Gulf Coast region	10,858	10,407	10,327	9,746	9,988	9,876	8,966
Rocky Mountain region							
Cedar Creek Anticline (2)	8,745	19,935	18,872	18,601	19,007	19,155	18,623
Other	5,163	4,958	4,819	4,516	4,831	5,392	4,594
Total Rocky Mountain region	13,908	24,893	23,691	23,117	23,838	24,547	23,217
Total non-tertiary production	24,766	35,300	34,018	32,863	33,826	34,423	32,183
Total production	63,823	74,052	71,531	71,466	73,718	75,320	73,810

(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 Cedar Creek Anticline ("CCA") on that date.

Total Production

Total production during the third quarter of 2014 averaged 73,810 BOE/d, an increase of 2,279 BOE/d (3%) compared to the third quarter of 2013 production levels and a decrease of 1,510 BOE/d (2%) compared to the second quarter of 2014 production levels. The change between the comparative third quarters was primarily a result of production increases from our tertiary oil fields, partially offset by interruption of non-tertiary production at CCA and Conroe fields during the current quarter and normal declines in our production at other non-tertiary fields, and the change comparing the sequential quarters of 2014 was also a result of these non-tertiary production decreases, partially offset by increases in our tertiary production at Bell Creek Field in our Rocky Mountain region. On a year-to-date basis, total production increased 4,453 BOE/d (6%) between the first nine months of 2013 and 2014, due primarily to the timing of the 2013 purchase of additional interests in CCA which closed in late March 2013, as well as production increases from our tertiary oil fields. Our production during the three and nine months ended September 30, 2014 was 96% and 95% oil, respectively, consistent with oil production of 95% and 94% during the three and nine months ended September 30, 2013.

Tertiary Production

We achieved record quarterly tertiary production during the third quarter of 2014, with average production of 41,627 Bbls/d. Third quarter of 2014 tertiary production increased 4,114 Bbls/d (11%) compared to tertiary production levels in the same period in 2013 and increased 730 Bbls/d (2%) when comparing tertiary production between the second and third quarters of 2014. These year-over-year and sequential-quarter increases were primarily due to production growth in response to continued field development and expansion of facilities in the tertiary floods at Hastings, Heidelberg and Oyster Bayou fields. In addition, tertiary production at Bell Creek Field has increased each quarter since its first tertiary production during the third quarter of 2013. We currently expect these same fields to drive additional tertiary production growth in the fourth quarter of 2014. The year-over-year increase was partially offset by normal declines in our mature tertiary fields, as well as the mid-2013 incident at Delhi Field. Under calculations based upon preliminary October 2014 Delhi operational information, it appears that "payout" (as defined in the agreements under which we purchased our Delhi Field interests) may have been achieved as of October 31, 2014, which under a reversionary interest could reduce our share of Delhi Field production by approximately 25% starting November 1, 2014, although several matters remain in dispute concerning the "payout" calculation, the reversionary interest and other issues that could ultimately affect the calculation and timing of "payout" and the Delhi Field seller's reversionary interest. Our mature tertiary properties are generally on decline with an average annual rate of approximately 12% during 2013. However, production from our mature tertiary properties has remained steady at approximately 12,000 Bbls/d thus far in 2014 as a result of continued optimization work.

Non-Tertiary Production

Production from our non-tertiary operations averaged 32,183 BOE/d during the third quarter of 2014, a decrease of 1,835 BOE/d (5%) compared to the third quarter of 2013 levels, and a sequential decrease of 2,240 BOE/d (7%) when compared to the second quarter of 2014 levels. These decreases were primarily due to unplanned downtime at various non-tertiary properties during the third quarter of 2014, principally at CCA in the Rocky Mountain region and Conroe Field in the Gulf Coast region. CCA production was negatively impacted by an electrical panel failure causing a water injection facility to be offline for approximately two months and Conroe Field production was reduced by downtime of a third-party processing plant for most of the quarter. The interruptions at CCA and Conroe fields resulted in non-tertiary production decreases of approximately 500 BOE/d and 800 BOE/d, respectively, during the third quarter of 2014. At Conroe Field, the third-party processing plant was returned to service, and the impacted production resumed late in the third quarter. At CCA, the electrical panel was repaired and water injection facility placed back in service late in the third quarter, which should allow for gradual production growth at the field during the fourth quarter. Additionally, natural gas production from Riley Ridge was negligible during the third quarter of 2014 due to continued unplanned downtime as a result of, among other things, design, equipment, machinery and mechanical well failures. We currently expect natural gas production at Riley Ridge will continue to be shut-in due to mechanical supply well failures until late-2015; however, we expect the near-term impact upon our operating cash flows to be minimal. Production from our other non-tertiary properties is generally on decline, and in some instances the decline is pronounced when non-tertiary wells are shut in as part of an initiation or expansion of our tertiary floods in a field or an area of a field.

Oil and Natural Gas Revenues

Our oil and natural gas revenues decreased 7% during the three months ended September 30, 2014 and increased 1% during the nine months ended September 30, 2014 compared to these revenues for the same periods in 2013. The changes in our oil and natural gas revenues are due to changes in production quantities and commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

	Three Months Ended September 30, 2014 vs. 2013		Nine Months Ended September 30, 2014 vs. 2013	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Increase in production	$21,240	3 %	$119,784	6 %
Decrease in commodity prices	(66,038)	(10)%	(95,548)	(5)%
Total increase (decrease) in oil and natural gas revenues	$(44,798)	(7)%	$24,236	1 %

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first, second, and third quarters and the nine months ended September 30, 2014 and 2013:

	Three Months Ended March 31,		Three Months Ended June 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013	2014	2013	2014	2013
Net realized prices:								
Oil price per Bbl	$97.69	$105.59	$100.04	$98.92	$94.78	$105.91	$97.49	$103.34
Natural gas price per Mcf	4.71	3.28	4.39	3.96	3.55	3.38	4.26	3.54
Price per BOE	94.03	99.87	95.86	94.70	91.60	101.32	93.83	98.55
NYMEX differentials:								
Oil per Bbl	$(0.91)	$11.17	$(3.03)	$4.78	$(2.53)	$(0.03)	$(2.16)	$5.13
Natural gas per Mcf	(0.02)	(0.21)	(0.19)	(0.05)	(0.40)	(0.18)	(0.16)	(0.15)

As reflected in the table above, our average net realized oil price, excluding the impact of commodity derivative contracts, decreased 11% during the third quarter of 2014 from the average price received during the third quarter of 2013. Company-wide oil price differentials in the third quarter of 2014 were $2.53 below NYMEX, compared to an average differential of $0.03 below NYMEX in the third quarter of 2013. During the third quarter of 2014, we sold approximately 43% of our crude oil at prices based on the Light Louisiana Sweet ("LLS") index price, approximately 23% 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. These percentages were consistent with those realized during the third quarter of 2013. The net oil differential we received was primarily impacted by positive differentials in the Gulf Coast region, offset by negative differentials in the Rocky Mountain region, each of which is discussed in further detail below.

Our average NYMEX oil differential in the Gulf Coast region was a positive $2.15 per Bbl and $3.42 per Bbl during the three months ended September 30, 2014 and 2013, respectively, and a positive $0.73 per Bbl during the three months ended June 30, 2014. These differentials are impacted significantly by the changes in prices received for our crude oil sold under LLS index prices relative to the change in NYMEX prices. This LLS-to-NYMEX differential declined from a positive $6.59 per Bbl average differential on a trade-month basis in the third quarter of 2013 to a positive $2.90 per Bbl in the second quarter of 2014 and a positive $3.41 per Bbl in the third quarter of 2014, with the two most recent quarters being more representative of longer-term historical differentials.

NYMEX oil differentials in the Rocky Mountain region averaged $11.96 per Bbl and $7.04 per Bbl below NYMEX during the three months ended September 30, 2014 and 2013, respectively, and $10.54 per Bbl below NYMEX during the three months ended June 30, 2014. Differentials in the Rocky Mountain region can move significantly over short periods of time due to refinery and transportation issues.

Prices received in a regional market fluctuate frequently and can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors and location differentials. Although we have seen the LLS and Rocky Mountain differentials improve somewhat in 2014 compared to the levels in the fourth quarter of 2013, we do not expect the LLS-to-NYMEX differential in the Gulf Coast region to return to the more favorable levels seen over the last few years due to the oil transportation capacity in that region that has been added, which allows more oil production access to the LLS market.

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during the month, as most of our natural gas is sold on an index price that is set near the first of each month. While the percentage change in NYMEX natural gas differentials can be quite large, the absolute impact of these changes on our results has historically been minor, as natural gas sales represented only approximately 1% of our oil and natural gas revenues during the nine months ended September 30, 2014.

Commodity Derivative Contracts

The following tables summarize the impact our oil and natural gas derivative contracts had on our operating results for the three and nine months ended September 30, 2014 and 2013:

In thousands	Three Months Ended September 30,					
	2014	2013	2014	2013	2014	2013
	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Receipt (payment) on settlements of commodity derivatives	$(25,016)	$(662)	$102	$—	$(24,914)	$(662)
Noncash fair value adjustments on commodity derivatives [(1)]	276,240	(79,784)	939	—	277,179	(79,784)
Total income (expense)	$251,224	$(80,446)	$1,041	$—	$252,265	$(80,446)

In thousands	Nine Months Ended September 30,					
	2014	2013	2014	2013	2014	2013
	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Payment on settlements of commodity derivatives	$(101,470)	$(662)	$(785)	$—	$(102,255)	$(662)
Noncash fair value adjustments on commodity derivatives [(1)]	102,521	(46,212)	559	—	103,080	(46,212)
Total income (expense)	$1,051	$(46,874)	$(226)	$—	$825	$(46,874)

(1) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure. See Operating Results Table above for a discussion of the reconciliation between noncash fair value adjustments on commodity derivatives to "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations.

To provide greater certainty to the range of our anticipated operating cash flows as we have transitioned to a dividend-paying entity, we entered into more fixed-price swaps for 2014 than we have historically. Prior to 2014, most of our derivative contracts were collars that had a floor and ceiling price that provided price protection at a lower level, but also a wider range of variability in operating cash flows than if we had used fixed-price swap contracts. In early 2014, our crude oil fixed-price swaps looked to be at or better than the futures prices for 2014, but as a result of rising oil prices throughout the first half of 2014, we paid out $25.0 million and $101.5 million during the three and nine months ended September 30, 2014, respectively. These settlements lowered our net realized oil price by $3.86 per Bbl and $5.27 per Bbl during the three and nine months ended September 30, 2014, respectively. Based on current futures prices as of November 3, 2014, which average roughly $79 per Bbl for the remainder of 2014, and the fixed price swaps that we have in place for the remainder of 2014, we currently expect that we will receive settlements from these contracts, the amount of which is dependent upon fluctuations in future NYMEX prices in relation to the fixed prices of these swaps, which have a weighted average price of $92.52 per Bbl for the fourth quarter of 2014.

Changes in the estimated fair value of our oil and natural gas derivative contracts are caused primarily by changes in commodity futures prices and the expiration of contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period change in the estimated fair value of these contracts, as outlined above, is recognized in our statements of operations. The details of our outstanding commodity derivative contracts are included in Note 5, Commodity Derivative Contracts, to the Unaudited Condensed Consolidated Financial Statements. Also, see Item 3, Quantitative and Qualitative Disclosures about Market Risk below for additional discussion on our commodity derivative contracts.

Production Expenses

Lease Operating Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data	2014	2013	2014	2013
Lease operating expense				
Tertiary – excluding Delhi remediation	$95,671	$86,534	$292,238	$256,283
Tertiary – Delhi remediation	(9,906)	28,000	(9,906)	98,000
Non-tertiary	69,433	66,433	206,495	187,784
Total lease operating expense	$155,198	$180,967	$488,827	$542,067
Lease operating expense per BOE				
Tertiary – excluding Delhi remediation	$24.98	$25.08	$26.23	$24.42
Tertiary – Delhi remediation	(2.58)	8.11	(0.89)	9.34
Non-tertiary	23.45	21.23	22.60	21.91
Total lease operating expense per BOE	22.86	27.50	24.10	28.43

Total lease operating expenses during the three and nine months ended September 30, 2014 decreased from the comparable 2013 periods on an absolute-dollar and per-BOE basis primarily due to Delhi remediation charges of $28.0 million and $98.0 million during the three and nine months ended September 30, 2013, respectively, compared to a net reduction of lease operating expenses of $9.9 million in the comparable 2014 periods. See Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release above for further discussion of the Delhi remediation costs and insurance reimbursements. Excluding Delhi remediation costs and insurance reimbursements, total lease operating expenses increased $12.1 million and $54.7 million on an absolute-dollar basis and $1.08 and $1.30 on a per-BOE basis during the three and nine months ended September 30, 2014, respectively, compared to levels in the same periods in 2013. The increase during both periods include (1) an increase in workover costs at Riley Ridge, (2) higher power cost and usage, and (3) costs associated with the expansion of our CO_2 floods, including our newest tertiary flood at Bell Creek Field. The increase on an absolute-dollar basis during the nine-month period is also driven by our acquisition of additional interests in CCA, which were acquired in late March of 2013, resulting in only approximately six months of CCA expenses in the first nine months of 2013. Sequentially, excluding Delhi remediation costs and insurance reimbursements, lease operating expenses remained relatively flat on an absolute-dollar and per-BOE basis between the second and third quarters of 2014. However, we have seen many of our costs decline compared to those realized in the fourth quarter of 2013 and first quarter of 2014, with the decrease in workover costs the primary component of lease operating expense cost reduction. Excluding Delhi remediation costs and insurance reimbursements and unplanned Riley Ridge well workovers, our lease operating expense per BOE decreased each sequential quarter in 2014 and decreased a total of 12% between the fourth quarter of 2013 and the third quarter of 2014.

Tertiary lease operating expenses decreased 25% on an absolute-dollar basis and 33% on a per-BOE basis during the third quarter of 2014 compared to the third quarter of 2013, primarily due to Delhi remediation charges of $28.0 million and $98.0 million during the three and nine months ended September 30, 2013, respectively (see Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release above), compared to a net reduction of lease operating expenses of $9.9 million in the comparable 2014 periods. Excluding Delhi remediation costs and insurance reimbursements, tertiary lease operating expenses increased $9.1 million and $36.0 million on an absolute-dollar basis and decreased $0.10 and increased $1.81 on a per-BOE basis during the three and nine months ended September 30, 2014, respectively, compared to the levels in the same periods in 2013. The increases on an absolute-dollar basis in both periods and the increase on a per-BOE basis for the nine-month period are primarily attributable to additional costs associated with our newest flood at Bell Creek Field which had initial production and operating expense in the third quarter of 2013, as well as its production being low relative to operating costs because production is still ramping up, resulting in high per-BOE operating costs, which is typical when we start up a new tertiary flood. The increase during the comparative nine-month periods is further impacted by a higher number of well workovers to repair well failures during the first quarter of 2014, and higher power costs due to higher rates and usage during 2014. When comparing sequential quarters, excluding Delhi remediation costs and insurance reimbursements, tertiary lease operating expenses decreased by 6% on a per-BOE basis between the second and third quarters of 2014.

Currently, our CO_2 expense comprises approximately one-fourth of our typical tertiary lease operating expenses, and for the CO_2 reserves we already own, consists of 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 third quarter of 2014, approximately 64% of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned 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 during the third quarter of 2014 was approximately $0.40 per Mcf, including taxes paid on CO_2 production but excluding depreciation and amortization of capital. This rate during the third quarter of 2014 was slightly lower than the $0.42 per Mcf comparable measure during the second quarter of 2014 and higher than the $0.37 per Mcf spent during the third quarter of 2013, with these fluctuations primarily due to fluctuations in pricing of our Rocky Mountain region CO_2 and changes in the oil price index. Including the cost of depreciation and amortization of capital expended at our CO_2 source fields and anthropogenic sources, but excluding depreciation of our CO_2 pipelines, our cost of CO_2 was $0.51 per Mcf and $0.46 per Mcf during the third quarters of 2014 and 2013, respectively.

Non-tertiary lease operating expenses increased 5% on an absolute-dollar basis and 10% on a per-BOE basis between the three months ended September 30, 2013 and 2014, primarily due to the addition of Riley Ridge workover costs of approximately $8 million in the current quarter. Non-tertiary lease operating expenses increased 10% on an absolute-dollar basis and 3% on a per-BOE basis between the nine months ended September 30, 2013 and 2014, also primarily due to workover costs at Riley Ridge, as well as our late-March 2013 purchase of additional interests in CCA, which caused an increase in costs, but which properties generally have a lower operating cost on a per-BOE basis than our other non-tertiary properties. On a sequential-quarter basis, our non-tertiary lease operating expenses increased $5.1 million (8%) on an absolute-dollar basis and $2.90 (14%) on a per-BOE basis during the third quarter of 2014, primarily due to an increase in workover costs at Riley Ridge. The increase on a per-BOE basis is further impacted by the decrease in non-tertiary production during the quarter (see further discussion in Non-Tertiary Production above).

Taxes Other Than Income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income decreased $9.3 million and increased $4.5 million during the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013. The levels of taxes other than income during most periods are generally aligned with fluctuations in oil and natural gas revenues. However, the decrease during the three-month period is impacted by a cumulative $7.5 million reduction in severance taxes at Hastings Field for a state-approved enhanced oil recovery project exemption. In addition, the increase during the nine-month period is further impacted by the change in the mix of properties subject to production and ad valorem taxes primarily as a result of the CCA acquisition.

General and Administrative Expenses ("G&A")

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data and employees	2014	2013	2014	2013
Gross cash compensation and administrative costs	$87,355	$82,653	$265,400	$247,171
Gross stock-based compensation	10,986	10,032	33,343	30,791
Operator labor and overhead recovery charges	(42,763)	(43,272)	(128,836)	(125,064)
Capitalized exploration and development costs	(15,212)	(13,444)	(46,896)	(41,658)
Net G&A expense	$40,366	$35,969	$123,011	$111,240
G&A per BOE:				
Net administrative costs	$4.72	$4.32	$4.88	$4.69
Net stock-based compensation	1.22	1.15	1.19	1.15
Net G&A expense	$5.94	$5.47	$6.07	$5.84
Employees as of September 30	1,502	1,494		

Gross cash compensation and administrative costs on an absolute-dollar basis increased $4.7 million (6%) and $18.2 million (7%) during the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013, primarily due to higher compensation-related costs, insurance, and professional services. The increase during the nine-month period was further impacted by the prior-year period including a $1.9 million insurance reimbursement.

Net G&A expense on a per-BOE basis increased 9% and 4% during the three and nine months ended September 30, 2014, respectively, compared to levels in the same periods in 2013. The increase between the comparative three- and nine-month periods was primarily due to higher compensation-related costs, partially offset by an increase in capitalized exploration and development costs and an increase in production during 2014. The increase between the nine-month periods was further impacted by the 2013 period including a $1.9 million insurance reimbursement.

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 cash compensation and 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 3% during the nine months ended September 30, 2014 compared to the amounts recovered in the same period in 2013. Capitalized exploration and development costs increased between both comparative periods, primarily due to increased compensation costs subject to capitalization.

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Interest and Financing Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data and interest rates	2014	2013	2014	2013
Cash interest expense	$47,158	$50,828	$147,115	$155,308
Noncash interest expense	3,456	3,441	10,434	10,581
Less: capitalized interest	(5,862)	(19,768)	(17,413)	(64,752)
Interest expense, net	$44,752	$34,501	$140,136	$101,137
Interest expense, net per BOE	$6.59	$5.24	$6.91	$5.31
Average debt outstanding	$3,622,579	$3,278,972	$3,618,149	$3,260,030
Average interest rate [1]	5.2 %	6.2 %	5.4 %	6.4 %

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

As reflected in the table above, our average interest rate was lower in both the three and nine months ended September 30, 2014 than in the same periods in 2013. The lower rates in 2014 include the impact of our April 2014 long-term debt refinancing, whereby we issued $1.25 billion of 5½% Notes to replace our $996.3 million of 8¼% Notes. The lower rates in the 2014 periods further reflect our refinancing in February 2013 of certain senior subordinated notes which had interest rates of 9½% and 9¾% with our 4 % Senior Subordinated Notes due 2023. In conjunction with these two refinancing transactions, we estimate that we will save approximately $60 million annually in cash interest expense on the principal amount of the refinanced notes; however, our savings will be partially offset by the incremental principal amount of the newly issued senior subordinated notes, some of which was used to repay lower rate bank debt. Although our cash interest costs are lower, as a result of completing major projects on which we had been previously capitalizing interest, specifically the Riley Ridge gas processing facility, Greencore Pipeline and the tertiary flood at Bell Creek, our capitalized interest in the 2014 periods decreased significantly, contributing to an increase in net interest expense of $10.3 million (30%) and $39.0 million (39%) between the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data	2014	2013	2014	2013
Depletion and depreciation of oil and natural gas properties	$114,224	$98,473	$337,841	$283,579
Depletion and depreciation of CO_2 properties	7,041	6,603	22,341	20,872
Asset retirement obligations	2,207	2,117	6,605	6,337
Depreciation of pipelines, plants and other property and equipment	23,088	18,402	69,067	54,612
Total DD&A	$146,560	$125,595	$435,854	$365,400
DD&A per BOE:				
Oil and natural gas properties	$17.15	$15.28	$16.99	$15.21
CO_2, pipelines, plants and other property and equipment	4.43	3.80	4.50	3.96
Total DD&A cost per BOE	$21.58	$19.08	$21.49	$19.17

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 and asset retirement obligations increased 16% and 19% on an absolute-dollar basis for the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013. The increase on an absolute-dollar basis was due to both higher production volumes and a higher depletion rate per BOE compared to the same periods in 2013. The DD&A rate per BOE for oil and natural gas properties increased 12% for both the three and nine months ended September 30, 2014, compared to levels in the same periods in 2013, primarily due to the recognition in late 2013 of proved reserves at Bell Creek Field and the related reclassification of costs from unevaluated to evaluated, and higher forecasted development costs.

Depletion and depreciation of our CO_2 properties, pipelines, plants, and other property and equipment increased 20% and 21% on an absolute-dollar and 17% and 14% on a per-BOE basis during the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013, primarily due to the startup of the Riley Ridge gas processing facility in late 2013 and additional pipelines and CO_2 properties placed in service. The lower rate of increase on a per-BOE basis (compared to the absolute-dollar measure) was due to higher production volumes in the 2014 periods.

We are required each quarter to perform a ceiling test calculation under full cost accounting rules, and we test goodwill for impairment annually during the fourth quarter, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of our reporting unit below its carrying amount. We did not have a ceiling test write-down or goodwill impairment at September 30, 2014; 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 or goodwill impairments in the future. The possibility and amount of any future write-down or impairment 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 and operating costs, as well as additional capital spent. See Item 1a, Risk Factors, for further discussion.

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE amounts and tax rates	2014	2013	2014	2013
Current income tax expense	$214	$16,019	$532	$23,367
Deferred income tax expense	167,356	41,292	168,967	169,634
Total income tax expense	$167,570	$57,311	$169,499	$193,001
Average income tax expense per BOE	$24.68	$8.71	$8.36	$10.12
Effective tax rate	38.4 %	36.0 %	38.4 %	37.7 %

Our income taxes are based on estimated statutory rates of approximately 38% and 38.5% in 2014 and 2013, respectively. Our effective tax rate for the three and nine months ended September 30, 2014 was slightly above our estimated statutory rate, primarily due to a reduction in the domestic production activities deduction and the inclusion of differences between our 2013 tax provision and our 2013 filed tax returns. For the three and the nine months ended September 30, 2013, our effective tax rate was below our estimated statutory rate due to a change in the expected completion date of the Riley Ridge gas processing facility, as well as the change in tax treatment of certain items between our 2012 tax provision and our 2012 filed tax returns. The amounts recorded as current income tax expense represent our federal taxes, reduced by enhanced oil recovery credits during the 2013 periods, plus our state income taxes. The lower level of current income taxes during the three and nine months ended September 30, 2014 was primarily due to tax benefits related to the loss on extinguishment of debt recognized during the second quarter of 2014. The higher level of deferred income taxes during three months ended September 30, 2014 was primarily due to the noncash fair value gain on our commodity derivatives during the third quarter of 2014.

As of September 30, 2014, we had an estimated $15.0 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 2014 or future years. These 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 would not currently expect to earn additional enhanced oil recovery credits unless oil prices were to significantly deteriorate.

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 September 30,		Nine Months Ended September 30,	
Per-BOE data	2014	2013	2014	2013
Oil and natural gas revenues	$91.60	$101.32	$93.83	$98.55
Payment on settlements of commodity derivatives	(3.67)	(0.10)	(5.04)	(0.03)
Lease operating expenses – excluding Delhi Field remediation	(24.32)	(23.24)	(24.59)	(23.29)
Lease operating expenses – Delhi Field remediation	1.46	(4.26)	0.49	(5.14)
Production and ad valorem taxes	(5.34)	(7.00)	(6.22)	(6.43)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.63)	(1.39)	(1.82)	(1.45)
Production netback	58.10	65.33	56.65	62.21
CO_2 and helium sales, net of operating and exploration expenses	—	0.39	0.57	0.45
General and administrative expenses	(5.94)	(5.47)	(6.07)	(5.84)
Interest expense, net	(6.59)	(5.24)	(6.91)	(5.31)
Other	1.00	(1.57)	1.08	(0.29)
Changes in assets and liabilities relating to operations	3.56	(7.02)	(1.67)	1.88
Cash flow from operations	50.13	46.42	43.65	53.10
DD&A	(21.58)	(19.08)	(21.49)	(19.17)
Deferred income taxes	(24.65)	(6.28)	(8.33)	(8.89)
Loss on early extinguishment of debt	—	—	(5.62)	(2.34)
Noncash fair value adjustments on commodity derivatives	40.82	(12.12)	5.08	(2.42)
Other noncash items	(5.14)	6.57	0.12	(3.51)
Net income	$39.58	$15.51	$13.41	$16.77

CRITICAL ACCOUNTING POLICIES

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

FORWARD-LOOKING INFORMATION

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in the section Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of

1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted production, cash flows and capital expenditures, levels of dividend payments in future periods, drilling activity or methods including the timing and location thereof, pending or planned acquisitions or dispositions, development activities, estimated timing of completion of pipeline construction and the cost thereof, 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 and their availability, 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, possible asset impairments, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, estimates of the range of potential insurance recoveries, 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," "may," or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil and/or natural gas prices and consequently in the prices received or demand for the Company's oil and natural gas; levels of future capital expenditures; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results; operating hazards and remediation costs; disruption of operations and damages from well incidents, 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 Company's most recent Form 10-K.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

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. As of September 30, 2014, we had $410.0 million in outstanding borrowings on our bank credit facility. 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. 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.

The following table presents the principal balances of our debt, by maturity date, as of September 30, 2014:

In thousands	2015	2016	2017	2021	2022	2023	Total
Variable rate debt:							
Bank Credit Facility (weighted average interest rate of 1.9% at September 30, 2014)	$—	$410,000	$—	$—	$—	$—	$410,000
Fixed rate debt:							
6 % Senior Subordinated Notes due 2021	—	—	—	400,000	—	—	400,000
5½% Senior Subordinated Notes due 2022	—	—	—	—	1,250,000	—	1,250,000
4 % Senior Subordinated Notes due 2023	—	—	—	—	—	1,200,000	1,200,000
Other Subordinated Notes	484	—	2,250	—	—	—	2,734

See Note 3, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements for details regarding our long-term debt, including information regarding our April 2014 debt issuance (at a lower interest rate and for a longer term) and repurchase and redemption of our outstanding 8¼% Senior Subordinated Notes due 2020.

Oil and Natural Gas Derivative Contracts

We have historically entered 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. 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. To provide greater certainty to the range of our anticipated operating cash flows as we transitioned to a dividend-paying entity, in late 2013 we entered into more fixed-price swaps for 2014 than we have historically. Prior to 2014, most of our derivative contracts were collars that had a floor and ceiling price that provided price protection at a lower level, but also a wider range of variability in operating cash flows than if we had used fixed-price swap contracts. We anticipate that we may use more fixed-price swaps in the future or a combination of fixed-price swaps and collars as we look to provide more certainty around our cash flows in order to execute on our capital development plans, pay dividends and retain a healthy balance sheet. We may also look to hedge further out than the 18 months to two years we have typically hedged, potentially up to three years, in order to provide greater certainty around oil and natural gas prices and projected cash flows for an extended period. See Notes 5 and 6 to the Unaudited Condensed Consolidated

Financial Statements for additional information regarding our commodity derivative contracts.

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

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

At September 30, 2014, our commodity derivative contracts were recorded at their fair value, which was a net asset of $55.8 million, a $103.1 million increase from the $47.3 million net liability recorded at December 31, 2013. This change is related to the expiration of commodity derivative contracts during 2014, new commodity derivative contracts we entered into during 2014 for future periods, and to the changes in oil and natural gas futures prices between December 31, 2013 and September 30, 2014.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices and natural gas futures prices as of September 30, 2014, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as shown in the following table:

In thousands	Receipt / (Payment) Crude Oil Derivative Contracts	Natural Gas Derivative Contracts
Based on:		
Futures prices as of September 30, 2014	$50,230	$265
10% increase in prices	(128,835)	(350)
10% decrease in prices	250,479	1,940

Our commodity derivative contracts are used as an economic hedge of our exposure to commodity price risk associated with anticipated future production. As a result, changes in receipts or payments of our commodity derivative contracts due to changes in commodity prices as reflected in the above table would be mostly offset by a corresponding increase or decrease in the cash receipts on sales of our oil or natural gas production to which those commodity derivative contracts relate.

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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 September 30, 2014, 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 third quarter of fiscal 2014, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Information with respect to the Company's risk factors has been incorporated by reference to Item 1A of the Form 10-K, supplemented as follows: Item 1A of the Form 10-K included a risk factor entitled Our results of operations could be negatively affected as a result of goodwill impairments. In addition to this risk as discussed in the Form 10-K, our market capitalization has recently declined significantly, largely as a result of the recent rapid decline in market oil prices. These or further declines in market oil prices and/or our market capitalization may increase the risk of goodwill impairments in future periods. There have been no other material changes to the risk factors contained in the Form 10-K since its filing.

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 third quarter of 2014:

Month	Total Number of Shares Purchased (1)	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) (2)
July 2014	23,243	$17.93	—	$221.9
August 2014	11,225	16.74	—	221.9
September 2014	5,997	15.97	—	221.9
Total	40,465		—	

(1) Stock repurchases during the third quarter of 2014 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.

(2) In October 2011, our Board of Directors approved a common stock repurchase program for up to $500 million of Denbury's common stock, which was increased by an additional $271.2 million in November 2012, $140.7 million in November 2013, and $250.0 million in December 2013, for a total authorization under the program of $1.162 billion. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

Between early October 2011, when we announced the commencement of a common share repurchase program, and September 30, 2014, we repurchased 60.0 million shares of Denbury common stock (approximately 14.9% of our outstanding shares of common stock at September 30, 2011) for $940.0 million, or $15.68 per share.

Item 3. Defaults upon Senior Securities

None

Item 4. Mine Safety Disclosures

None

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Item 5. Other Information

Corrected Second Restated Certificate of Incorporation and Second Amended and Restated Bylaws

Although not an amendment to its Certificate of Incorporation, effective with its filing with the Delaware Secretary of State on October 30, 2014, the Company filed a Second Restated Certificate of Correction to its Certificate of Incorporation in order to correct two erroneous cross-references therein. The corrected Second Restated Certificate of Incorporation is filed as Exhibit 3(a) to this report. Separately, effective November 4, 2014, the Board of Directors amended and restated the Company's bylaws to make changes to certain procedural provisions, including those affecting meetings of committees of the Board of Directors. The amended and restated bylaws are filed as Exhibit 3(b) to this report.

Item 6. Exhibits

Exhibit No.	Exhibit
3(a)*	Second Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on October 30, 2014.
3(b)*	Second Amended and Restated Bylaws of Denbury Resources Inc. dated as of November 4, 2014.
4(a)	Indenture for 5½% Senior Subordinated Notes due 2022, dated as of April 30, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on May 1, 2014, File No. 001-12935).
4(b)	Third Supplemental Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of April 30, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 of Form 8-K filed by the Company on May 1, 2014, File No. 001-12935).
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.
November 7, 2014	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer
November 7, 2014	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer

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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.