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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2015
OR

☐ **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 ☑ No ☐

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 ☑ No ☐

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 ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

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

Class	Outstanding at July 31, 2015
Common Stock, $.001 par value	355,450,643

Denbury Resources Inc.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	June 30, 2015	December 31, 2014
Assets		
Current assets		
Cash and cash equivalents	$ 4,413	$ 23,153
Accrued production receivable	163,942	181,761
Trade and other receivables, net	98,857	156,955
Derivative assets	268,025	440,359
Deferred tax assets, net	8,060	—
Other current assets	15,085	10,452
Total current assets	558,382	812,680
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	9,994,968	9,782,337
Unevaluated properties	936,736	918,406
CO_2 properties	1,172,262	1,162,538
Pipelines and plants	2,279,813	2,269,564
Other property and equipment	466,362	468,051
Less accumulated depletion, depreciation, amortization and impairment	(6,388,348)	(4,248,652)
Net property and equipment	8,461,793	10,352,244
Derivative assets	696	66,187
Goodwill	1,261,512	1,283,590
Other assets	212,920	213,101
Total assets	$ 10,495,303	$ 12,727,802
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 228,942	$ 394,758
Oil and gas production payable	114,953	128,170
Derivative liabilities	641	—
Deferred tax liabilities	—	81,727
Current maturities of long-term debt	38,105	35,470
Total current liabilities	382,641	640,125
Long-term liabilities		
Long-term debt, net of current portion	3,471,141	3,535,900
Asset retirement obligations	132,213	126,411
Deferred tax liabilities	2,084,208	2,694,842
Other liabilities	25,066	26,668
Total long-term liabilities	5,712,628	6,383,821
Commitments and contingencies (Note 7)		
Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $.001 par value, 600,000,000 shares authorized; 414,023,232 and 411,779,911 shares issued, respectively	414	412
Paid-in capital in excess of par	3,225,728	3,230,418
Retained earnings	2,092,350	3,392,465
Accumulated other comprehensive loss	(174)	(209)
Treasury stock, at cost, 58,667,781 and 58,415,507 shares, respectively	(918,284)	(919,230)
Total stockholders' equity	4,400,034	5,703,856
Total liabilities and stockholders' equity	$ 10,495,303	$ 12,727,802

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Revenues and other income				
Oil, natural gas, and related product sales	$ 366,891	$ 657,029	$ 664,361	$ 1,280,875
CO_2 and helium sales and transportation fees	7,152	11,822	14,124	22,583
Interest income and other income	2,651	3,269	5,858	10,406
Total revenues and other income	376,694	672,120	684,343	1,313,864
Expenses				
Lease operating expenses	132,170	163,250	273,254	333,629
Marketing and plant operating expenses	14,215	18,149	25,900	34,935
CO_2 and helium discovery and operating expenses	945	5,590	1,892	10,795
Taxes other than income	33,555	50,850	60,234	96,795
General and administrative expenses	37,947	38,952	84,227	82,645
Interest, net of amounts capitalized of $8,738, $5,795, $17,147, and $11,551, respectively	39,863	46,550	79,962	95,384
Depletion, depreciation, and amortization	147,940	148,164	297,898	289,294
Commodity derivatives expense (income)	48,926	174,771	(34,150)	251,440
Loss on early extinguishment of debt	—	113,908	—	113,908
Write-down of oil and natural gas properties	1,705,800	—	1,852,000	—
Total expenses	2,161,361	760,184	2,641,217	1,308,825
Income (loss) before income taxes	(1,784,667)	(88,064)	(1,956,874)	5,039
Income tax provision (benefit)	(636,168)	(32,864)	(700,629)	1,929
Net income (loss)	$ (1,148,499)	$ (55,200)	$ (1,256,245)	$ 3,110
Net income (loss) per common share				
Basic	$ (3.28)	$ (0.16)	$ (3.59)	$ 0.01
Diluted	$ (3.28)	$ (0.16)	$ (3.59)	$ 0.01
Dividends declared per common share	$ 0.0625	$ 0.0625	$ 0.1250	$ 0.1250
Weighted average common shares outstanding				
Basic	350,039	347,803	349,653	349,267
Diluted	350,039	347,803	349,653	351,566

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income (loss)	$ (1,148,499)	$ (55,200)	$ (1,256,245)	$ 3,110
Other comprehensive income, net of income tax:				
Interest rate lock derivative contracts reclassified to income, net of tax of $10, $11, $21, and $24, respectively	18	17	35	32
Total other comprehensive income	18	17	35	32
Comprehensive income (loss)	$ (1,148,481)	$ (55,183)	$ (1,256,210)	$ 3,142

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Cash flows from operating activities		
Net income (loss)	$ (1,256,245)	$ 3,110
Adjustments to reconcile net income (loss) to cash flows from operating activities		
Depletion, depreciation, and amortization	297,898	289,294
Write-down of oil and natural gas properties	1,852,000	—
Deferred income taxes	(700,508)	1,611
Stock-based compensation	14,967	17,217
Commodity derivatives expense (income)	(34,150)	251,440
Receipt (payment) on settlements of commodity derivatives	272,616	(77,341)
Loss on early extinguishment of debt	—	113,908
Amortization of debt issuance costs and discounts	4,501	6,978
Other, net	(4,019)	(3,402)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	17,683	(25,236)
Trade and other receivables	57,865	12,921
Other current and long-term assets	(7,770)	(2,989)
Accounts payable and accrued liabilities	(71,892)	(36,178)
Oil and natural gas production payable	(13,217)	(2,033)
Other liabilities	(3,008)	(4,595)
Net cash provided by operating activities	426,721	544,705
Cash flows from investing activities		
Oil and natural gas capital expenditures	(276,783)	(451,564)
Acquisitions of oil and natural gas properties	(20,374)	—
CO_2 capital expenditures	(15,608)	(29,901)
Pipelines and plants capital expenditures	(20,349)	(34,530)
Purchases of other assets	(3,473)	(3,620)
Net proceeds from sales of oil and natural gas properties and equipment	131	1,736
Other	(56)	977
Net cash used in investing activities	(336,512)	(516,902)
Cash flows from financing activities		
Bank repayments	(1,007,000)	(1,315,000)
Bank borrowings	962,000	1,420,000
Repayment of senior subordinated notes	—	(997,345)
Premium paid on repayment of senior subordinated notes	—	(101,342)
Proceeds from issuance of senior subordinated notes	—	1,250,000
Costs of debt financing	(1,632)	(17,551)
Common stock repurchase program	—	(211,356)
Cash dividends paid	(43,528)	(43,461)
Other	(18,789)	(11,889)
Net cash used in financing activities	(108,949)	(27,944)
Net decrease in cash and cash equivalents	(18,740)	(141)
Cash and cash equivalents at beginning of period	23,153	12,187
Cash and cash equivalents at end of period	$ 4,413	$ 12,046

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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 an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil 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, 2014 (the "Form 10-K"). Unless indicated otherwise or the context requires, the terms "we," "our," "us," "Company" or "Denbury," refer to Denbury Resources Inc. and its subsidiaries.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end, and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the year. In management's opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair statement of our consolidated financial position as of June 30, 2015, our consolidated results of operations for the three and six months ended June 30, 2015 and 2014, and our consolidated cash flows for the six months ended June 30, 2015 and 2014.

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 (Loss) per Common Share

Basic net income (loss) per common share is computed by dividing the net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of stock options, stock appreciation rights ("SARs"), nonvested restricted stock and nonvested performance-based equity awards. For the three and six months ended June 30, 2015 and 2014, there were no adjustments to net income (loss) for purposes of calculating basic and diluted net income (loss) per common share.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2015	2014	2015	2014
Basic weighted average common shares outstanding	350,039	347,803	349,653	349,267
Potentially dilutive securities				
Restricted stock, stock options, SARs and performance-based equity awards	—	—	—	2,299
Diluted weighted average common shares outstanding	350,039	347,803	349,653	351,566

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

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 (loss) per common share (although all non-performance-based restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares during the six months ended June 30, 2014, the nonvested restricted stock, stock options, SARs and performance-based equity awards 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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2015	2014	2015	2014
Stock options and SARs	9,949	4,949	10,228	4,601
Restricted stock and performance-based equity awards	2,241	1,337	2,595	679

Oil and Natural Gas Properties

Ceiling Test. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved oil and natural gas reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as those costs have previously been incurred by the Company. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes. The cost center ceiling test is prepared quarterly.

As a result of the precipitous decline in NYMEX oil prices since the fourth quarter of 2014, the rolling first-day-of-the-month average oil price for the preceding 12 months, after adjustments for market differentials by field, was $79.55 per Bbl for the first quarter of 2015 and $68.48 per Bbl for the second quarter of 2015. In addition, the first-day-of-the-month average natural gas price for the preceding 12 months, after adjustments for market differentials by field, was $3.95 per Mcf for the first quarter of 2015 and $3.74 per Mcf for the second quarter of 2015. Because of the significant decrease in pricing during the fourth quarter of 2014 and its continued decline in the first and second quarters of 2015, we recognized full cost pool ceiling test write-downs of $1.7 billion and $0.2 billion during the three months ended June 30, 2015 and March 31, 2015, respectively. We currently expect that we will continue to record material write-downs in the third and fourth quarters of 2015 if oil and natural gas prices remain at or near late-July 2015 levels for the remainder of 2015, as the 12-month average price used in determining the full cost ceiling value would continue to decline during each rolling quarterly period in 2015, and also depending, in part, upon changes in proved oil and natural gas reserve volumes, future capital expenditures and operating costs.

Goodwill

We test goodwill for impairment annually during the fourth quarter; however, as a result of the relationship between our market capitalization and our book value of stockholders' equity and the sustained decrease in our share price, we also performed a goodwill impairment assessment as of June 30, 2015. Because our enterprise value (combined market capitalization plus a control premium of 10% and the fair value of our long-term debt) was below the combined book value of our stockholders' equity and long-term debt as of June 30, 2015, we were required to proceed to step two of the goodwill impairment test. Oil and natural gas reserves, which represent the most significant assets requiring valuation, were estimated using the expected present value of future cash flows method based on June 30, 2015, NYMEX oil and natural gas futures prices for the next five years, adjusted for current price differentials. Consistent with the results of our fourth quarter 2014 goodwill analysis, the implied fair value of goodwill calculated in this quantitative assessment exceeded the corresponding book value of goodwill. Therefore, we did not record any goodwill impairment during the second quarter of 2015, nor have we recorded a goodwill impairment historically. Subsequent to June 30, 2015, our enterprise value declined at a rate in excess of the decline in NYMEX oil prices. If this relationship continues until we perform our next goodwill impairment assessment as of September 30, 2015, we could incur a partial or full impairment of our $1.3 billion goodwill balance, the amount of the impairment (if any) depending upon further changes in our enterprise value, oil and natural gas futures prices, and other key assumptions.

Recent Accounting Pronouncements

Debt Issuance Costs. In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-03, *Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs* ("ASU 2015-03"). ASU 2015-03 requires debt issuance costs related to a recognized debt liability to be presented as a direct reduction of the carrying amount of that debt in the balance sheet, consistent with the presentation of debt discounts. The amendments in this ASU are effective for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years, and early adoption is permitted. Entities will be required to apply the guidance on a retrospective basis to each period presented as a change in accounting principle. The adoption of ASU 2015-03 is currently not expected to have a material effect on our consolidated financial statements, other than balance sheet reclassifications.

Consolidation. In February 2015, the FASB issued ASU 2015-02, *Consolidation: Amendments to the Consolidation Analysis* ("ASU 2015-02"). ASU 2015-02 amends the guidance for consolidation of certain types of legal entities. Under the ASU, all reporting entities are required to evaluate whether they should consolidate certain legal entities under the revised consolidation model. The amendment focuses on limited partnerships and similar legal entities, fees paid to a decision maker or a service provider as a variable interest, fee arrangements and related party effects on the primary beneficiary determination and certain investment funds. The amendments in this ASU are effective for annual periods beginning after December 15, 2015, and interim periods within those years, and early adoption is permitted. Entities can transition to the standard either retrospectively to each period presented or as a cumulative-effect adjustment as of the beginning of the fiscal year of adoption. The adoption of ASU 2015-02 is currently not expected to have a material effect on our consolidated financial statements.

Revenue Recognition. In May 2014, the FASB issued 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 currently effective for reporting periods beginning after December 15, 2016. However, in July 2015, the FASB affirmed their proposal to delay the effective date for one year and are awaiting final approval through an ASU, and early adoption will be permitted. 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.

Note 2. Long-Term Debt

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

In thousands	June 30, 2015	December 31, 2014
Bank Credit Agreement	$ 350,000	$ 395,000
6⅜% Senior Subordinated Notes due 2021	400,000	400,000
5½% Senior Subordinated Notes due 2022	1,250,000	1,250,000
4⅝% Senior Subordinated Notes due 2023	1,200,000	1,200,000
Other Subordinated Notes, including premium of $9 and $11, respectively	2,743	2,746
Pipeline financings	216,552	220,583
Capital lease obligations	89,951	103,041
Total	3,509,246	3,571,370
Less: current obligations	(38,105)	(35,470)
Long-term debt and capital lease obligations	$ 3,471,141	$ 3,535,900

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, and the guarantees of the notes are full and unconditional and joint and several; any subsidiaries of DRI that are not subsidiary guarantors of certain of such notes are minor subsidiaries.

Bank Credit Facility

In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). The Bank Credit Agreement is a senior secured revolving credit facility with an initial borrowing base of $3.0 billion and aggregate lender commitments of $1.6 billion. Loans under the Bank Credit Agreement mature in December 2019. The weighted average interest rate on borrowings outstanding as of June 30, 2015, under the Bank Credit Agreement was 1.5%. The undrawn portion of the aggregate lender commitments under the Bank Credit Agreement is subject to a commitment fee ranging from 0.3% to 0.375% per annum. As of June 30, 2015, we were in compliance with all debt covenants under the Bank Credit Agreement.

Borrowing base redeterminations under our Bank Credit Agreement occur annually, and with the first such redetermination having been completed in early-May 2015, our next scheduled redetermination is set for May 2016. However, the lenders may, at their election, request one interim redetermination between annual scheduled redeterminations. In connection with the borrowing base redetermination completed in early-May 2015, we elected to maintain our aggregate lender commitments at $1.6 billion; however, due to a reduction in oil prices used by our lenders in determining the borrowing base value of our proved reserves attributable to our oil and natural gas properties, our borrowing base was reduced from the previous level of $3.0 billion to $2.6 billion. Because we continue to maintain a significant cushion between our borrowing base and the aggregate lender commitments, and because we had significant availability with respect to our aggregate lender commitments as of June 30, 2015, this borrowing base reduction has no impact on our liquidity.

In conjunction with the May 2015 redetermination, we also entered into the First Amendment to the Bank Credit Agreement (the "First Amendment"). This First Amendment restructures certain financial covenants in 2016, 2017, and 2018 in order to provide more flexibility in managing our balance sheet and managing the credit extended by our lenders if oil prices remain low over the next several years. The covenant changes included in the First Amendment were as follows:

- In 2016 and 2017, suspend the maximum permitted ratio of consolidated total net debt to consolidated EBITDAX covenant of 4.25 to 1.0 and replace it with a maximum permitted ratio of consolidated senior secured debt to consolidated EBITDAX covenant of 2.5 to 1.0 during the same time period. Currently, only debt under our Bank Credit Agreement would be considered consolidated senior secured debt for purposes of this ratio.

- Beginning in the first quarter of 2018, reinstate the ratio of consolidated total net debt to consolidated EBITDAX covenant utilizing an annualized EBITDAX amount for the first quarter of 2018 and building to a trailing four quarters by the end of 2018, with the maximum permitted ratios being 6.0 to 1.0 for the first quarter ended March 31, 2018, 5.5 to 1.0 for the second quarter ended June 30, 2018, and 5.0 to 1.0 for the third and fourth quarters ended September 30 and December 31, 2018, and returning to 4.25 to 1.0 for the first quarter ended March 31, 2019.
- In 2016 and 2017, institute a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 2.25 to 1.0.

The restructuring of covenants through the First Amendment was executed in consideration of a fee paid to the lenders. The First Amendment has no impact on the current ratio financial performance covenant, which will remain in place in 2015 and beyond. All of the above descriptions of financial covenants are qualified by the express language and defined terms contained in the Bank Credit Agreement.

2014 Issuance of 5½% Senior Subordinated Notes due 2022

In April 2014, we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022 (the "5½% Notes"), which were sold at par. The net proceeds, after issuance costs, of $1.23 billion were used to repurchase or redeem our outstanding $996.3 million of 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes") (see *2014 Repurchase and Redemption of 8¼% Senior Subordinated Notes due 2020* below) and to pay down a portion of outstanding borrowings under our previous bank credit agreement.

2014 Repurchase and Redemption of 8¼% Senior Subordinated Notes due 2020

During the second quarter of 2014, we repurchased and redeemed the entire $996.3 million outstanding principal amount of our 8¼% Notes using a portion of the proceeds from the issuance of the 5½% 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 Statements 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 3. Income Taxes

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to our ordinary income or loss to calculate our estimated tax liability or benefit. As of June 30, 2015, we had $37.0 million of deferred tax assets associated with State of Louisiana net operating losses. As the result of a new tax law enacted in the State of Louisiana effective June 30, 2015, which limits a company's utilization of certain deductions, including our net operating loss carryforwards, we recognized a tax valuation allowance of $30.5 million to reduce the carrying value of our deferred tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized. Our effective tax rate for the three and six months ended June 30, 2015, was lower than our estimated statutory rate, primarily due to the impact of the tax valuation allowance discussed above, which reduced the net deferred tax benefit recognized.

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Note 4. Stockholders' Equity

During the second quarter of 2015, we reduced the number of shares of our common stock reported as outstanding by 1,430,819 shares (approximately 0.4% of our outstanding shares at March 31, 2015). This reduction is the result of a correction to properly reflect the number of shares actually issued in the merger with Encore Acquisition Company ("Encore") in March 2010. The stock and cash consideration originally issued and paid in the Encore merger was valued at $3.0 billion, which would have been reduced by $22.1 million for this share correction. As a result, we have recorded adjustments in the accompanying June 30, 2015, Unaudited Condensed Consolidated Balance Sheet to reflect a decrease in consideration paid in the Encore merger through a reduction of "Goodwill" ($22.1 million), offset by a reduction in an equal amount of the Company's stockholders' equity ($22.1 million). We determined that this correction in outstanding shares (1) had no impact on net income (loss) for the second quarter of 2015, our estimated results of operations for the year ending December 31, 2015, or for any prior period, and (2) was not material to our consolidated balance sheet, statement of cash flows, or basic or diluted earnings per common share for the second quarter of 2015, or for any prior period, and therefore we recorded the cumulative effect of correcting these items during the three months ended June 30, 2015.

Dividends

In each of the first two quarters of both 2015 and 2014, the Company's Board of Directors declared quarterly cash dividends of $0.0625 per common share, or an annual rate of $0.25 per common share. Dividends totaling $43.5 million were paid to stockholders during the six months ended June 30, 2015 and 2014. See Note 9, *Subsequent Event*, for details regarding the dividend declared and to be paid in the third quarter of 2015.

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. In November 2014, the Company's Board of Directors suspended the common share repurchase program in light of commodity price uncertainty and to protect our financial position.

Employee Stock Purchase Program

We previously provided for an Employee Stock Purchase Plan (the "Plan") in which funds from eligible employees, together with Company contributions, were used to purchase previously unissued Denbury common stock or treasury stock that we purchased in the open market for that purpose, in either case, based on the market value of our common stock at the end of each quarter. The Plan was terminated, effective at the end of the offering period ended on March 31, 2015, as all of the previously authorized shares reserved for issuance under the Plan had been issued.

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 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 historically 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, financial strength and expectation of future commodity prices. For the past several years, we have generally hedged a substantial portion of our forecasted production over an approximately 18 month to two year future period, as we believed it was beneficial to protect our future cash flow at then-projected oil prices for those future periods. During the significant and rapid decline in oil prices in late-2014 and the first quarter of 2015, we deferred entering into new derivative contracts, and therefore currently have less of our production hedged and for a shorter future time period than we have generally had over the last several years. During the second quarter of 2015, we entered into new oil hedging positions covering the second and third quarters of 2016 in order to provide more certainty to our future cash flows in those quarters.

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 (or affiliates of such lenders). As of June 30, 2015, 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 June 30, 2015, none of which are classified as hedging instruments in accordance with the Financial Accounting Standards Board Codification ("FASC") *Derivatives and Hedging* topic:

			Contract Prices (1)					
					Weighted Average Price			
Months	Index Price	Volume (2)	Range (3)		Swap	Sold Put	Floor	Ceiling
Oil Contracts:								
2015 Enhanced Swaps (4)								
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								
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 Fixed-Price Swaps								
Apr – June	NYMEX	11,500	$ 60.30	– 63.75	$ 61.84	$ —	$ —	$ —
Apr – June	LLS	3,500	64.20	– 66.15	64.99	—	—	—
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
2016 Collars								
Apr – June	NYMEX	5,000	$ 55.00	– 72.25	$ —	$ —	$ 55.00	$ 71.01
Apr – June	LLS	2,000	58.00	– 73.00	—	—	58.00	73.00
July – Sept	NYMEX	4,500	55.00	– 72.65	—	—	55.00	71.22
July – Sept	LLS	3,000	58.00	– 74.30	—	—	58.00	73.85
Natural Gas Contracts:								
2015 Collars								
July – 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 paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the "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 and fixed-price swaps that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). The fixed-price swap features of our enhanced swaps are valued using a discounted cash flow model based upon forward commodity price curves. Our costless collars and the sold 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, 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 June 30, 2015, instruments in this category include non-exchange-traded enhanced swaps, costless collars and three-way collars that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). The valuation models utilized for enhanced swaps, costless collars and three-way collars are consistent with the methodologies described above; however, the implied volatilities utilized in the valuation of Level 3 instruments are developed using a benchmark, which is considered a significant unobservable input. An increase or decrease of 100 basis points in the implied volatility inputs utilized in our fair value measurement would result in a change of approximately $0.8 million in the fair value of these instruments as of June 30, 2015.

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Notes to Unaudited Condensed Consolidated Financial Statements

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
June 30, 2015				
Assets:				
Oil and natural gas derivative contracts – current	$ —	$ 155,972	$ 112,053	$ 268,025
Oil and natural gas derivative contracts – long-term	—	391	305	696
Total Assets	$ —	$ 156,363	$ 112,358	$ 268,721
Liabilities:				
Oil and natural gas derivative contracts – current	$ —	$ 641	$ —	$ 641
Oil and natural gas derivative contracts – long-term	—	—	—	—
Total Liabilities	$ —	$ 641	$ —	$ 641
December 31, 2014				
Assets:				
Oil and natural gas derivative contracts – current	$ —	$ 283,238	$ 157,121	$ 440,359
Oil and natural gas derivative contracts – long-term	—	34,862	31,325	66,187
Total Assets	$ —	$ 318,100	$ 188,446	$ 506,546

Since we do not apply hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in "Commodity derivatives expense (income)" in the accompanying 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 six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2015	2014	2015	2014
Fair value of Level 3 instruments, beginning of period	$ 165,015	$ (6,097)	$ 188,446	$ 6,709
Fair value adjustments on commodity derivatives	(7,302)	(33,019)	17,783	(45,825)
Receipt on settlements of commodity derivatives	(45,355)	—	(93,871)	—
Fair value of Level 3 instruments, end of period	$ 112,358	$ (39,116)	$ 112,358	$ (39,116)
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	$ (4,325)	$ (33,019)	$ 14,142	$ (45,825)

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 calculation, including contractual prices for the underlying instruments, maturity, forward prices for commodities, interest rates, volatility factors and credit worthiness, and the fair value estimate is prepared and reviewed on a quarterly basis. 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 6/30/2015 (in thousands)	Valuation Technique	Unobservable Input	Range
Oil derivative contracts	$ 112,358	Discounted cash flow / Black-Scholes	Volatility of Light Louisiana Sweet for settlement periods beginning after June 30, 2015	16.0% - 33.6%

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 debt as of June 30, 2015 and December 31, 2014, excluding pipeline financing and capital lease obligations, was $2,867.7 million and $2,938.6 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 regulatory proceedings incidental to our businesses. 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. 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. Although a single or multiple adverse rulings or settlements could possibly have a material adverse effect on our finances, we only accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

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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. Virtually all of our total cost estimate of $130.8 million has been incurred.

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 in October 2014 related to the Delhi Field release and remediation from our insurance carrier providing the first layer of our excess insurance coverage. We have not reached any agreement with our remaining carriers as to further reimbursements, but given our belief that under our policies we are entitled to reimbursement of between approximately one-third and two-thirds of our total costs, we have filed suit to pursue further reimbursements, the ultimate outcome of which cannot be predicted.

In March 2015, Evolution Petroleum Company ("Evolution"), the parent of the entity which sold Denbury Onshore, LLC ("Denbury Onshore") its original interest in Delhi Field, filed an amended petition in a lawsuit which has been pending in the Texas district court in Houston since December 2013. Originally, that lawsuit involved ongoing disputes between Denbury Onshore and Evolution regarding the terms of the purchase documents under which Denbury Onshore bought its original Delhi Field interest, including disputes regarding allocation of costs in determining "payout" as defined in the agreements, and the extent and terms of assignment of reversionary interests in the Unit back to Evolution following payout, along with related contractual terms. The amended petition added allegations of negligence and gross negligence against Denbury Onshore in connection with the June 2013 Delhi Field release, and for the first time estimated its damages attributable to its allegations in the case as exceeding $200 million. The amended petition also adds a claim for unspecified punitive damages. There has only been limited discovery in the case to date, and Evolution has not specified the basis for the amount of its claimed damages estimate. The case is currently set for trial in April 2016. We believe Evolution's claims with respect to this matter are without merit and intend to vigorously defend against them and pursue our rights under the purchase documents.

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Note 8. Additional Balance Sheet Details

Trade Accounts Receivable, net

In thousands	June 30, 2015	December 31, 2014
Trade accounts receivable, net	$ 43,291	$ 45,407
Commodity derivatives settlement receivables	38,896	59,755
Federal income tax receivable, net	—	37,652
Other receivables	16,670	14,141
Total	$ 98,857	$ 156,955

Accounts Payable and Accrued Liabilities

In thousands	June 30, 2015	December 31, 2014
Accrued interest	$ 48,802	$ 48,255
Accrued lease operating expenses	36,029	56,798
Accrued compensation	33,702	62,513
Accounts payable	31,805	64,604
Taxes payable	30,654	39,816
Accrued exploration and development costs	19,590	90,939
Other	28,360	31,833
Total	$ 228,942	$ 394,758

Note 9. Subsequent Event

Dividend Declaration

On July 28, 2015, the Board of Directors declared a dividend of $0.0625 per share on our outstanding common stock, payable on September 29, 2015, to stockholders of record at the close of business on August 25, 2015.

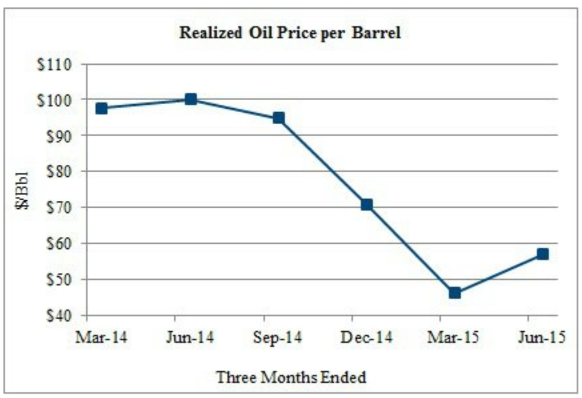
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

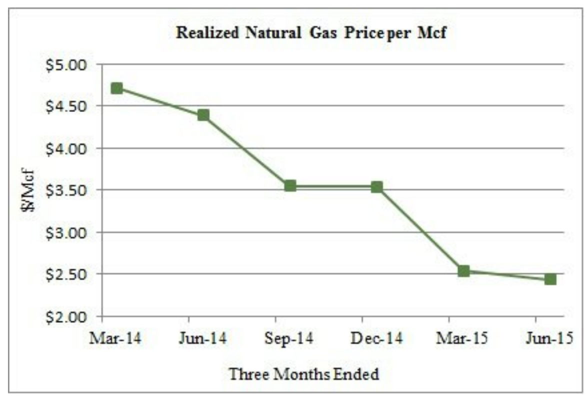
The following discussion and analysis should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and Notes thereto included herein and our Consolidated Financial Statements and Notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2014 (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 an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

Oil Price Decline and Impact on Our Business. Oil prices generally constitute the single largest variable in our operating results. Although oil prices have historically been volatile, during the second half of 2014 and continuing into 2015, oil prices dropped significantly, with NYMEX prices declining from $107 per Bbl in June 2014 to less than $44 per Bbl in March 2015, ending June 2015 at $59 per Bbl, and declining to $47 per Bbl at the end of July 2015. The following charts illustrate the fluctuations in our realized oil and natural gas prices, excluding the impact of derivative settlements, during 2014 and the first two quarters of 2015.





	Three Months Ended					
	3/31/2014	6/30/2014	9/30/2014	12/31/2014	3/31/2015	6/30/2015
Oil price per Bbl	$ 97.69	$ 100.04	$ 94.78	$ 70.80	$ 46.02	$ 56.92
Natural gas price per Mcf	4.71	4.39	3.55	3.54	2.54	2.44

In response to the decline in oil prices, we (1) limited our projected 2015 development capital spending to $550 million, or roughly half of 2014 levels, (2) are focusing on cost reductions and identifying new innovation and improvement ideas for our fields, which has resulted in meaningful decreases to date in most categories of our lease operating expenses, general and administrative expenses, and cost savings on capital projects, and (3) modified certain of our bank covenants applicable to the 2016, 2017 and 2018 periods to eliminate concern around our ability to access our bank credit line if oil prices remain low for an extended period of time. We believe that the current low oil price environment highlights the degree to which the unique attributes of our CO_2 enhanced oil recovery operations allows us to maintain relatively flat production for periods of time while spending at significantly reduced levels.

Operating Highlights. Our financial results have been significantly impacted by the decrease in realized oil prices as highlighted above, which decreased from an average of $100.04 per Bbl in the second quarter of 2014 to $56.92 in the second quarter of 2015. During the second quarter of 2015, we recognized a net loss of $1.1 billion, or $3.28 per diluted common share, primarily due to a full cost pool ceiling test write-down of our oil and natural gas properties totaling $1.7 billion ($1.1 billion net of tax) (see *Full Cost Pool Ceiling Test Write-Down* below), plus commodity derivatives expense of $48.9 million. Comparatively, although oil prices were significantly higher in the second quarter of 2014, we recorded a net loss of $55.2 million, or $0.16 per diluted common share, due primarily to commodity derivatives expense of $174.8 million and a $113.9 million loss on the early extinguishment of debt. Other significant changes between the second quarters of 2015 and 2014 were a $290.1 million (44%) decline in our oil and natural gas revenues between the periods, which was primarily oil-price related, offset in part by a $31.1 million (19%) reduction in lease operating expense, a $17.3 million (34%) decrease in taxes other than income, and a $6.7 million (14%) decrease in interest, net. The $125.8 million positive change in commodity derivatives expense (income) between the two periods was principally due to receipts of $124.2 million upon settlement of derivative contracts in the second quarter of 2015 compared to payments of $50.2 million in the prior-year quarter, with the remaining change resulting from an increase in the loss related to noncash fair value adjustments on commodity derivatives.

We generated $289.0 million of cash flows from operating activities in the second quarter of 2015, compared to $137.8 million in the first quarter of 2015 and $329.8 million in the prior-year second quarter. The sequential increase in cash flows from operations was due primarily to quarter-to-quarter increases in oil prices, which caused an increase in oil revenues, as well as reductions in lease operating expenses, general and administrative expenses, and changes in working capital items, partially offset by a decline in derivative settlements. The decrease in cash flows from operations between the second quarter of 2014 and 2015 was due primarily to lower oil prices, which caused a decrease in oil revenues, partially offset by significant positive changes in derivative settlements and, to a lesser extent, reductions in lease operating expenses, taxes other than income, interest expense, and changes in working capital items. Despite recent significant decreases in oil prices, based upon oil futures prices at the end of July 2015, we currently expect to generate significant cash flow above and beyond our capital expenditures and dividends for 2015.

During the second quarter of 2015, our oil and natural gas production, which was 95% oil, averaged 73,716 BOE/d, compared to an average of 75,320 BOE/d produced during the second quarter of 2014 and 74,356 BOE/d during the first quarter of 2015. The year-over-year 2% decrease in production is attributable to a 10% decline in production from our non-tertiary properties, partially offset by a 4% increase in our tertiary oil production. Oil production from our tertiary operations during the second quarter of 2015 increased 1,687 Bbls/d (4%) compared to tertiary production levels in the same period in 2014, and increased 757 Bbls/d (2%) when comparing tertiary production between the second quarter of 2015 and first quarter of 2015. As a result of weather-related flooding in south Texas during late-May 2015, Thompson Field was shut-in during June 2015, resulting in lower production of approximately 500 BOE/d during the second quarter of 2015, which accounts for most of the drop in our production from the levels in the first quarter of 2015. Excluding the Thompson Field impact and the reversionary interest at Delhi Field in the fourth quarter of 2014, which reduced our production by approximately 1,200 Bbls/d in the second quarter of 2015, our production would have been consistent or higher than that in the second quarter of 2014. See *Results of Operations – Production* for additional discussion.

Our average realized oil price per barrel, excluding the impact of commodity derivative contracts, was $56.92 per Bbl during the second quarter of 2015, a decrease of 43% compared to $100.04 per Bbl realized during the second quarter of 2014 and an increase of 24% compared to $46.02 per Bbl realized during the first quarter of 2015. The oil price we realized relative to NYMEX oil prices (our NYMEX oil price differential) was $0.89 per Bbl below NYMEX prices in the second quarter of 2015, compared to a negative $3.03 per Bbl NYMEX differential in the second quarter of 2014, and a negative $2.81 per Bbl NYMEX differential in the first quarter of 2015. This improvement in our oil price differential in both comparative periods was driven by an increase in the Light Louisiana Sweet ("LLS") index premium and a decrease in the Rocky Mountain region discount relative to NYMEX oil prices.

One of our primary focuses in 2014 and 2015 has been to reduce costs throughout the organization, through a number of internal initiatives. Our efforts have proven successful, and our lease operating expenses in the second quarter of 2015 were less than $20 per BOE, the lowest per-BOE level in nearly three years. In addition, excluding Delhi remediation costs and insurance reimbursements and unplanned Riley Ridge well workovers, both in 2014, our recurring lease operating expenses per BOE decreased each sequential quarter in 2014 and in the first two quarters of 2015 and decreased a total of 25% between the fourth quarter of 2013 and the second quarter of 2015, with decreases realized in most categories of lease operating expenses, the most significant of which included workover costs, power costs, CO_2 costs, and certain third-party contractor and vendor costs. On a sequential-quarter basis, lease operating expenses per BOE decreased 7% between the first quarter of 2015 and the second quarter of 2015, and our goal is to continue to find efficiencies in both capital project costs and per-barrel operating costs.

Full Cost Pool Ceiling Test Write-Down. Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the first-day-of-the-month average oil and natural gas price for each month during a 12-month rolling period ended as of each quarterly reporting period. The first-day-of-the-month average oil price for the preceding 12 months, after adjustments for market differentials by field, was $79.55 per Bbl for the first quarter of 2015 and $68.48 per Bbl for the second quarter of 2015. In addition, the first-day-of-the-month average natural gas price for the preceding 12 months, after adjustments for market differentials by field, was $3.95 per Mcf for the first quarter of 2015 and $3.74 per Mcf for the second quarter of 2015. The prices used for the second quarter of 2015 represent a decrease of 25% for crude oil and 13% for natural gas prices compared to adjusted prices used to calculate the December 31, 2014, full cost ceiling value. As a result of the significant decrease in average pricing during the fourth quarter of 2014 and its continued decline in the first and second quarters of 2015, we recognized full cost pool ceiling test write-downs of $1.7 billion and $0.2 billion during the three months ended June 30, 2015 and March 31, 2015, respectively. See *Results of Operations – Full Cost Pool Ceiling Test Write-Down* and Note 1, *Basis of Presentation – Oil and Natural Gas Properties*, to the Unaudited Condensed Consolidated Financial Statements for additional information regarding the ceiling test.

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, and for 2015, based upon oil futures prices at the end of July 2015, we currently expect to generate cash flow above and beyond our capital expenditures and dividends. Our cash flow from operations during the first half of 2015 was $426.7 million, which was $166.1 million higher than our development capital expenditures and dividends incurred during the first six months of the year. We used this excess cash flow from operations primarily to reduce debt, acquire oil and gas properties, and cover working capital outflows, including cash outflows to cover accruals for capital items as of December 31, 2014.

As discussed in the *Overview* above, we have been proactive in adjusting our 2015 capital spending and dividend plans in connection with the current lower oil price environment. We project that we will have adequate capital resources and liquidity for the foreseeable future because (1) we have significant borrowing capacity on our bank credit facility with no scheduled borrowing base redetermination until May 2016, although the lenders may, at their election, request an interim redetermination prior to that date (see Note 2, *Long-Term Debt*, and *Bank Credit Facility* below); (2) we have commodity derivative contracts in place to cover a significant portion of our forecasted oil production for 2015 and the first half of 2016 that will lessen the impact of the current lower oil price environment (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 flows from operations; (4) we can significantly reduce our capital expenditures for some time, as we have done in 2015, and still maintain relatively flat or slightly lower 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 occur six or more years in the future and carry attractive fixed interest rates ranging between 4⅝% and 6⅜%.

If oil prices remain at relatively low levels beyond 2015, our cash flows from operations will likely be significantly lower than current levels, as our commodity derivative contracts presently in place for 2016 cover significantly less forecasted oil production and are at lower prices. Therefore, we continue to focus on reducing our operating and administrative costs so as to preserve as much of our profit margin as possible in this lower oil price environment, and if this low oil price environment persists, we intend to continue to make adjustments to our capital spending plans to preserve our financial health. Fortunately, some of our costs, such as CO_2 purchases and production taxes, adjust proportionally with changes in the price of oil. We also expect that our cost of services and equipment will continue to come down in this lower oil price environment, but this likely will not reflect as large a percentage decrease as the decrease in the price of oil. As we have done in 2015, we can reduce capital spending and maintain production at relatively flat or slightly lower production levels for some time.

2015 Capital Spending. We anticipate that our full-year 2015 capital budget, excluding acquisitions, will be $550 million, which includes approximately $85 million in capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods. This combined 2015 capital budget amount, excluding acquisitions, is comprised of the following:

- $320 million allocated for tertiary oil field expenditures;
- $100 million allocated for other areas, primarily non-tertiary oil field expenditures;
- $30 million to be spent on CO_2 sources;
- $15 million for pipeline construction; and
- $85 million for other capital items such as capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods.

During the six months ended June 30, 2015, we incurred capital expenditures of $217.1 million, excluding acquisitions. See additional detail on our expenditures in the *Capital Expenditure Summary* below.

Based on oil and natural gas commodity futures prices in early-August 2015, our current production forecast, and our commodity derivative contracts covering a substantial portion of our anticipated 2015 production, we currently anticipate that our 2015 cash flows from operations will be in excess of our combined 2015 capital budget and currently-planned dividend payments. During the first six months of 2015, we used excess cash flow from operations to pay down borrowings on our bank credit facility, with a total reduction of $45.0 million from the level outstanding as of December 31, 2014. If prices were to decrease further from July 2015 levels, or changes in operating results were to cause us to have a significant reduction in our currently forecasted operating cash flows, we could reduce our capital expenditures or reduce our current dividend payment; however, we currently have ample availability on our bank credit facility to cover any potential foreseeable shortfall. If we further reduce our capital spending due to lower cash flows, any sizeable reduction could lower our anticipated production levels in future years.

Bank Credit Facility. Borrowing base redeterminations under our Bank Credit Agreement occur annually, and with the first such redetermination having been completed in early-May 2015, our next scheduled redetermination is set for May 2016. However, the lenders may, at their election, request one interim redetermination between annual scheduled redeterminations. In connection with the borrowing base redetermination completed in early-May 2015, we elected to maintain our aggregate lender commitments at $1.6 billion; however, due to a reduction in oil prices used by our lenders in determining the borrowing base value of our proved reserves attributable to our oil and natural gas properties, our borrowing base was reduced from the previous level of $3.0 billion to $2.6 billion. Because we continue to maintain a $1.0 billion cushion between our borrowing base and the aggregate lender commitments, even after this borrowing base reduction, and because we had availability of $1.2 billion with respect to our aggregate lender commitments as of June 30, 2015, this borrowing base reduction has no impact on our liquidity.

Currently, our Bank Credit Agreement contains certain restrictive covenants, plus two principal financial performance covenants to maintain (1) a ratio of consolidated total net debt to consolidated EBITDAX of not more than 4.25 to 1.0 and (2) a ratio of consolidated current assets to consolidated current liabilities ("current ratio") not less than 1.0. For these financial performance covenant calculations as of June 30, 2015, our ratio of consolidated total net debt to consolidated EBITDAX was 2.82 to 1.0, and our current ratio was 4.44, and we currently project to be in compliance with the covenants through the remainder of 2015.

In conjunction with the May 2015 redetermination, we entered into the First Amendment to the Bank Credit Agreement (the "First Amendment") under which we modified certain financial covenants in 2016, 2017 and 2018 in order to provide more flexibility in managing our balance sheet and managing the credit extended by our lenders if oil prices remain low over the next several years. The covenant changes included in the First Amendment were as follows:

- In 2016 and 2017, suspend the maximum permitted ratio of consolidated total net debt to consolidated EBITDAX covenant of 4.25 to 1.0 and replace it with a maximum permitted ratio of consolidated senior secured debt to consolidated EBITDAX covenant of 2.5 to 1.0 during the same time period. Currently, only debt under our Bank Credit Agreement would be considered consolidated senior secured debt for purposes of this ratio. If this covenant had been in place as of June 30, 2015, our ratio of senior secured debt to consolidated EBITDAX would have been 0.28 to 1.0 as of that date.

- Beginning in the first quarter of 2018, reinstate the ratio of consolidated total net debt to consolidated EBITDAX covenant utilizing an annualized EBITDAX amount for the first quarter of 2018 and building to a trailing four quarters by the end of 2018, with the maximum permitted ratios being 6.0 to 1.0 for the first quarter ended March 31, 2018, 5.5 to 1.0 for the second quarter ended June 30, 2018, and 5.0 to 1.0 for the third and fourth quarters ended September 30 and December 31, 2018, and returning to 4.25 to 1.0 for the first quarter ended March 31, 2019.
- In 2016 and 2017, institute a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 2.25 to 1.0. If this covenant had been in place as of June 30, 2015, our ratio of consolidated EBITDAX to consolidated interest charges would have been 6.29 to 1.0 as of that date.

The restructuring of covenants through the First Amendment was executed in consideration of a fee paid to the lenders. The First Amendment has no impact on the current ratio financial performance covenant, which will remain in place in 2015 and beyond. All of the above descriptions of financial covenants are qualified by the express language and defined terms contained in the Bank Credit Agreement.

Dividends. In each of the first two quarters of both 2015 and 2014, the Company's Board of Directors declared quarterly cash dividends of $0.0625 per common share. Dividends totaling $43.5 million were paid to stockholders during the six months ended June 30, 2015 and 2014. See Note 9, *Subsequent Event*, to the Unaudited Condensed Consolidated Financial Statements for details regarding the dividend declared in the third quarter of 2015. An annual dividend rate of $0.25 per common share would result in total dividend payments of approximately $89 million to our stockholders in 2015. The declaration and payment of future dividends are 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, market conditions, 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. As of June 30, 2015, virtually all of our total cost estimate of $130.8 million had been incurred.

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 in October 2014 related to the Delhi Field release and remediation from our insurance carrier providing the first layer of our excess insurance coverage. We have not reached any agreement with our remaining carriers as to further reimbursements, but given our belief that under our policies we are entitled to reimbursement of between approximately one-third and two-thirds of our total costs, we have filed suit to pursue further reimbursements, the ultimate outcome of which cannot be predicted.

Capital Expenditure Summary. The following table of capital expenditures includes accrued capital for the six months ended June 30, 2015 and 2014:

	Six Months Ended June 30,	
In thousands	2015	2014
Capital expenditures by project		
Tertiary oil fields	$ 96,594	$ 286,396
Non-tertiary fields	52,579	122,981
Capitalized interest and internal costs (1)	48,499	45,702
Oil and natural gas capital expenditures	197,672	455,079
CO_2 pipelines	6,296	12,356
CO_2 sources (2)	10,482	28,237
CO_2 capitalized interest and other	2,603	2,052
Capital expenditures, before acquisitions	217,053	497,724
Acquisitions of oil and natural gas properties	21,959	—
Capital expenditures, total	$ 239,012	$ 497,724

(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.

For the first six months of 2015 and 2014, our capital expenditures and property acquisitions were fully funded with cash flows from operations.

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, 2014, 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*.

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 six months ended June 30, 2015 and 2014 are included in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share and unit data	2015	2014	2015	2014
Operating results				
Net income (loss) [1]	$ (1,148,499)	$ (55,200)	$ (1,256,245)	$ 3,110
Net income (loss) per common share – basic [1]	(3.28)	(0.16)	(3.59)	0.01
Net income (loss) per common share – diluted [1]	(3.28)	(0.16)	(3.59)	0.01
Dividends declared per common share	0.0625	0.0625	0.1250	0.1250
Net cash provided by operating activities	288,957	329,847	426,721	544,705
Average daily production volumes				
Bbls/d	69,837	71,051	70,199	70,446
Mcf/d	23,273	25,614	23,014	24,463
BOE/d [2]	73,716	75,320	74,034	74,523
Operating revenues				
Oil sales	$ 361,732	$ 646,799	$ 654,002	$ 1,260,779
Natural gas sales	5,159	10,230	10,359	20,096
Total oil and natural gas sales	$ 366,891	$ 657,029	$ 664,361	$ 1,280,875
Commodity derivative contracts [3]				
Receipt (payment) on settlements of commodity derivatives	$ 124,151	$ (50,172)	$ 272,616	$ (77,341)
Noncash fair value adjustments on commodity derivatives [4]	(173,077)	(124,599)	(238,466)	(174,099)
Commodity derivatives income (expense)	$ (48,926)	$ (174,771)	$ 34,150	$ (251,440)
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$ 56.92	$ 100.04	$ 51.47	$ 98.88
Natural gas price per Mcf	2.44	4.39	2.49	4.54
Unit prices – including impact of derivative settlements [3]				
Oil price per Bbl	$ 76.30	$ 92.32	$ 72.79	$ 92.88
Natural gas price per Mcf	2.89	4.27	2.90	4.34
Oil and natural gas operating expenses				
Lease operating expenses	$ 132,170	$ 163,250	$ 273,254	$ 333,629
Marketing expenses, net of third-party purchases, and plant operating expenses	12,494	13,524	22,337	25,787
Production and ad valorem taxes	29,718	47,520	52,617	89,934
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$ 54.69	$ 95.86	$ 49.58	$ 94.96
Lease operating expenses	19.70	23.82	20.39	24.73
Marketing expenses, net of third-party purchases, and plant operating expenses	1.86	1.97	1.66	1.91
Production and ad valorem taxes	4.43	6.93	3.93	6.67
CO_2 sources and helium – revenues and expenses				
CO_2 and helium sales and transportation fees	$ 7,152	$ 11,822	$ 14,124	$ 22,583
CO_2 and helium discovery and operating expenses	(945)	(5,590)	(1,892)	(10,795)
CO_2 and helium revenue and expenses, net	$ 6,207	$ 6,232	$ 12,232	$ 11,788

(1) Includes full cost pool ceiling test write-downs of $1.7 billion and $1.9 billion for the three and six months ended June 30, 2015, respectively.
(2) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas ("BOE").
(3) See also *Commodity Derivative Contracts* below and *Item 3. Quantitative and Qualitative Disclosures about Market Risk* for information concerning our derivative transactions.
(4) 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 receipts on settlements of $124.2 million and $272.6 million for the three and six months ended June 30, 2015, and payments on settlements of $50.2 million and $77.3 million for the three and six months ended June 30, 2014. 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.

Production

Average daily production by area for each of the four quarters of 2014 and for the first and second quarters of 2015 is shown below:

	Average Daily Production (BOE/d)					
Operating Area	First Quarter 2014	Second Quarter 2014	Third Quarter 2014	Fourth Quarter 2014	First Quarter 2015	Second Quarter 2015
Tertiary oil production						
Gulf Coast region						
Mature properties:						
Brookhaven	1,877	1,818	1,767	1,579	1,612	1,691
Eucutta	2,181	2,150	2,224	1,995	1,905	2,054
Mallalieu	1,837	1,839	1,869	1,653	1,574	1,537
Other mature properties (1)	6,283	6,156	6,189	5,864	5,710	5,888
Total mature properties	12,178	11,963	12,049	11,091	10,801	11,170
Delhi (2)	4,708	4,543	4,377	3,743	3,551	3,623
Hastings	4,618	4,759	4,917	4,811	4,694	5,350
Heidelberg	5,325	5,609	5,721	6,164	6,027	5,885
Oyster Bayou	4,055	4,415	4,605	5,638	5,861	5,936
Tinsley	8,430	8,518	8,310	8,767	8,928	8,740
Total Gulf Coast region	39,314	39,807	39,979	40,214	39,862	40,704
Rocky Mountain region						
Bell Creek	578	1,090	1,648	1,659	1,965	1,880
Total Rocky Mountain region	578	1,090	1,648	1,659	1,965	1,880
Total tertiary oil production	39,892	40,897	41,627	41,873	41,827	42,584
Non-tertiary oil and gas production						
Gulf Coast region						
Mississippi	2,513	2,319	2,346	2,099	1,761	1,400
Texas	6,444	6,508	5,537	6,677	6,490	6,304
Other	1,031	1,049	1,083	1,082	1,006	906
Total Gulf Coast region	9,988	9,876	8,966	9,858	9,257	8,610
Rocky Mountain region						
Cedar Creek Anticline	19,007	19,155	18,623	18,553	18,522	18,089
Other	4,831	5,392	4,594	4,591	4,750	4,433
Total Rocky Mountain region	23,838	24,547	23,217	23,144	23,272	22,522
Total non-tertiary production	33,826	34,423	32,183	33,002	32,529	31,132
Total production	73,718	75,320	73,810	74,875	74,356	73,716

(1) Other mature properties include Cranfield, Little Creek, Lockhart Crossing, Martinville, McComb and Soso fields.
(2) Beginning with the fourth quarter of 2014, average daily Delhi Field production amounts reflect the reversionary assignment of approximately 25% of our interest in that field effective November 1, 2014. The effectiveness, timing, and scope of the reversionary assignment are subject to ongoing litigation, the ultimate outcome of which cannot be predicted.

Total Production

Total production during the second quarter of 2015 averaged 73,716 BOE/d, a decrease of 1,604 BOE/d (2%) compared to second quarter of 2014 production levels and a decrease of 640 BOE/d (1%) compared to first quarter of 2015 production levels. During the second quarter of 2015, our production was impacted by weather-related flooding in south Texas during late-May 2015, which impacted quarterly production at Thompson Field by approximately 500 BOE/d, and minor downtime at other fields. Also, our ownership interest at Delhi Field decreased as of November 1, 2014, due to a contractual reversionary assignment of approximately 25% of our interest to the seller of the field which reduced our second quarter 2015 production by approximately 1,200 Bbls/d. Production increases at our newer tertiary floods were partially offset by these negative impacts to production. Excluding decreases as a result of the reversionary interest at Delhi Field in the fourth quarter of 2014 and the impact of weather-related downtime at Thompson Field in the second quarter of 2015, our production would have been consistent or higher than the second quarter of 2014. On a year-to-date basis, total production decreased 489 BOE/d (1%) between the first six months of 2014 and 2015 as a result of the factors discussed above. Our production during the three and six months ended June 30, 2015 was 95% oil, consistent with oil production of 94% and 95% during the three and six months ended June 30, 2014.

Tertiary Production

Oil production from our tertiary operations during the second quarter of 2015 increased 1,687 Bbls/d (4%) compared to tertiary production levels in the same period in 2014, and increased 757 Bbls/d (2%) when comparing tertiary production between the second quarter of 2015 and first quarter of 2015. The year-over-year increase was primarily due to production growth in response to continued field development and expansion of facilities in our tertiary floods at Hastings, Heidelberg, Oyster Bayou, and Tinsley fields in our Gulf Coast region and Bell Creek Field in our Rocky Mountain region. Partially offsetting the year-over-year increases were production declines in our mature tertiary fields, as well as the decrease in our ownership interest in Delhi Field due to the November 1, 2014, contractual reversionary assignment of approximately 25% of our interest to the seller of the field, the effectiveness, timing, and scope of which are subject to ongoing litigation. The sequential-quarter increase was primarily due to production growth at our mature properties and Hastings Field, which has begun to benefit from the partial implementation of a series flood, partially offset by minor declines at Tinsley and Heidelberg fields. In addition, the slight sequential decrease in production at Bell Creek Field is related to facility and compressor-related downtime as we optimize sweep efficiency.

Non-Tertiary Production

Production from our non-tertiary operations averaged 31,132 BOE/d during the second quarter of 2015, a decrease of 3,291 BOE/d (10%) compared to the second quarter of 2014 levels and decreased 1,397 BOE/d (4%) when compared to the first quarter of 2015 levels. These decreases include weather-related downtime at Thompson Field as noted above, weather-related power outages at Cedar Creek Anticline, and minor downtime at other fields. Additionally, natural gas production at Riley Ridge remained shut-in during the second quarter of 2015, compared to averaging 2,200 Mcf/d (367 BOE/d) in the second quarter of 2014. We currently expect that natural gas production at Riley Ridge will continue to be shut-in until at least mid-2016 as we develop and evaluate solutions to eliminate sulfur build-up in those wells. 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 during the three and six months ended June 30, 2015 decreased 44% and 48%, respectively, compared to these revenues for the same periods in 2014. The changes in our oil and natural gas revenues during the comparative three and six month periods 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 June 30, 2015 vs. 2014		Six Months Ended June 30, 2015 vs. 2014	
In thousands	Decrease in Revenues	Percentage Decrease in Revenues	Decrease in Revenues	Percentage Decrease in Revenues
Change in oil and natural gas revenues due to:				
Decrease in production	$ (13,998)	(2)%	$ (8,407)	(1)%
Decrease in commodity prices	(276,140)	(42)%	(608,107)	(47)%
Total decrease in oil and natural gas revenues	$ (290,138)	(44)%	$ (616,514)	(48)%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first quarters, second quarters, and six months ended June 30, 2015 and 2014:

	Three Months Ended March 31,		Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014	2015	2014
Net realized prices:						
Oil price per Bbl	$ 46.02	$ 97.69	$ 56.92	$ 100.04	$ 51.47	$ 98.88
Natural gas price per Mcf	2.54	4.71	2.44	4.39	2.49	4.54
Price per BOE	44.45	94.03	54.69	95.86	49.58	94.96
NYMEX differentials:						
Oil per Bbl	$ (2.81)	$ (0.91)	$ (0.89)	$ (3.03)	$ (1.87)	$ (1.97)
Natural gas per Mcf	(0.28)	(0.02)	(0.30)	(0.19)	(0.29)	(0.11)

As reflected in the table above, our average net realized oil price, excluding the impact of commodity derivative contracts, decreased 43% during the second quarter of 2015 from the average price received during the second quarter of 2014. Company-wide average oil price differentials in the second quarter of 2015 were $0.89 per Bbl below NYMEX, compared to an average differential of $3.03 per Bbl below NYMEX in the second quarter of 2014, as we have seen improvement in our price differentials. The oil differentials we received in the Gulf Coast and Rocky Mountain regions are discussed in further detail below.

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. Our average NYMEX oil differential in the Gulf Coast region was a positive $1.86 per Bbl and $0.73 per Bbl during the three months ended June 30, 2015 and 2014, respectively, and a negative $0.29 per Bbl during the three months ended March 31, 2015. 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 quarterly average LLS-to-NYMEX differential (on a trade-month basis) was a positive $6.29 per Bbl in the second quarter of 2015, up from a positive $2.90 per Bbl in the second quarter of 2014 and a positive $2.60 per Bbl in the first quarter of 2015. During the second quarter of 2015, we sold approximately 43% of our crude oil at prices based on the LLS index price, approximately 21% 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 second quarter of 2014.

NYMEX oil differentials in the Rocky Mountain region averaged $6.48 per Bbl and $10.54 per Bbl below NYMEX during the three months ended June 30, 2015 and 2014, respectively, and $7.75 per Bbl below NYMEX during the three months ended March 31, 2015. Differentials in the Rocky Mountain region can move significantly over short periods of time due to refinery and transportation issues, but are showing signs of greater stability as infrastructure and takeaway capacity improve in the region.

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 2% of our oil and natural gas revenues during the six months ended June 30, 2015.

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 six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,					
	2015	2014	2015	2014	2015	2014
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Receipt (payment) on settlements of commodity derivatives	$ 123,183	$ (49,895)	$ 968	$ (277)	$ 124,151	$ (50,172)
Noncash fair value adjustments on commodity derivatives (1)	(172,022)	(124,865)	(1,055)	266	(173,077)	(124,599)
Total expense	$ (48,839)	$ (174,760)	$ (87)	$ (11)	$ (48,926)	$ (174,771)

	Six Months Ended June 30,					
	2015	2014	2015	2014	2015	2014
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Receipt (payment) on settlements of commodity derivatives	$ 270,899	$ (76,454)	$ 1,717	$ (887)	$ 272,616	$ (77,341)
Noncash fair value adjustments on commodity derivatives (1)	(237,144)	(173,719)	(1,322)	(380)	(238,466)	(174,099)
Total income (expense)	$ 33,755	$ (250,173)	$ 395	$ (1,267)	$ 34,150	$ (251,440)

(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.

For the remainder of 2015, we have commodity derivative contracts consisting of a combination of enhanced swaps, collars, and three-way collars covering a total of 58,000 Bbls/d for the third quarter of 2015 and 38,000 Bbls/d for the fourth quarter of 2015. Roughly half of these 2015 derivative contracts are collars and three-way collars, so the variability in potential cash flows from these types of hedges exposes us to more downside price risk than our enhanced swaps. These 2015 collars and three-way collars, which include both NYMEX and LLS hedges, have a weighted average floor of approximately $83 per Bbl (approximately $81 per Bbl and $87 per Bbl for NYMEX and LLS hedges, respectively) and a weighted average ceiling price of approximately $97 per Bbl (approximately $96 per Bbl and $100 per Bbl for NYMEX and LLS hedges, respectively). Our three-way collars and enhanced swaps all include sold puts that have a weighted average price of approximately $68 per Bbl. The sold puts for our three-way collars and enhanced swaps limit the benefit that our hedges provide us to the extent that oil prices remain below the price of our sold puts.

Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our oil and natural gas derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period changes in the fair value of these contracts, as outlined above, are recognized in our statements of operations. The details of our outstanding commodity derivative contracts at June 30, 2015, 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 June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data	2015	2014	2015	2014
Lease operating expense				
Tertiary	$ 79,499	$ 98,869	$ 164,958	$ 196,568
Non-tertiary	52,671	64,381	108,296	137,061
Total lease operating expense	$ 132,170	$ 163,250	$ 273,254	$ 333,629
Lease operating expense per BOE				
Tertiary	$ 20.52	$ 26.57	$ 21.59	$ 26.88
Non-tertiary	18.59	20.55	18.80	22.19
Total lease operating expense per BOE	19.70	23.82	20.39	24.73

Our lease operating costs have declined as a result of our cost reduction efforts throughout 2014 and 2015, as well as general market decreases in the prices of many of the components of these costs, and our total lease operating expenses in the second quarter of 2015 were less than $20 per BOE. In addition, excluding Delhi remediation costs and insurance reimbursements and unplanned Riley Ridge well workovers, both of which occurred in 2014, our recurring lease operating expenses per BOE decreased in each of our last six sequential quarters and decreased a total of 25% between the fourth quarter of 2013 and the second quarter of 2015. Total lease operating expenses decreased $31.1 million (19%) and $60.4 million (18%) on an absolute-dollar basis or $4.12 (17%) and $4.34 (18%) on a per-BOE basis during the three and six months ended June 30, 2015, compared to levels in the same periods in 2014. The decrease during both periods was due to cost decreases in most categories of lease operating expenses, the most significant of which including (1) a decrease in workover costs, (2) lower power cost and usage, (3) lower CO_2 expense resulting from a decrease in CO_2 injection volumes and a decrease in the cost of CO_2 during both comparative periods, which correlates with oil prices, and (4) lower third-party contractor and vendor expenses such as contract labor and chemical costs. Sequentially, lease operating expenses declined 6% on an absolute-dollar basis and 7% on a per-BOE basis between the first and second quarters of 2015, as we have seen many of our costs decline, with the decrease in CO_2 and workover expense the primary components of lease operating expense cost reductions.

Tertiary lease operating expenses decreased $19.4 million and $31.6 million on an absolute-dollar basis and decreased $6.05 and $5.29 on a per-barrel basis during the three and six months ended June 30, 2015, respectively, compared to the levels in the same periods in 2014. The decreases in both periods were primarily due to (1) lower workover costs, (2) lower power costs due to lower rates and usage, (3) lower CO_2 expense resulting from a decrease in CO_2 injection volumes and a decrease in the cost of CO_2 during both comparative periods, which correlates with oil prices, and (4) lower third-party contractor and vendor expenses such as contract labor and chemical costs. As part of our innovation and improvement initiative, we have identified fields where we have been able to reduce CO_2 injections without impacting oil production. As such, we have been able to reduce injected CO_2 volumes in the Gulf Coast region by 16% when compared to those in the prior year second quarter, and by 25% on a sequential-quarter basis. In addition, our operating costs on a per-barrel basis have improved from those in the second quarter of 2014 based on an overall increase in total tertiary production, which was significantly impacted by production increases at Hastings, Oyster

Bayou and Bell Creek fields. When comparing the second quarter of 2015 to the first quarter of 2015, tertiary lease operating expenses decreased \$6.0 million (7%) or \$2.18 (10%) on a per-barrel basis. For any specific field, we expect our tertiary lease operating expense per barrel to be high initially, as we experienced in 2013 and 2014 with our Bell Creek flood, and then decrease as production increases, ultimately leveling off until production begins to decline in the later life of the field, when operating expense per barrel will again increase.

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 industrial sources. During the second quarters of 2015 and 2014, approximately 58% and 64%, respectively, of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned and produced by us. 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 second quarter of 2015 was approximately \$0.33 per Mcf, including taxes paid on CO_2 production but excluding depletion and depreciation of capital. This rate during the second quarter of 2015 was lower than the \$0.42 per Mcf during the second quarter of 2014, primarily driven by reductions in commodity costs due to the significant decline in oil prices, and was higher than the \$0.29 per Mcf comparable measure during the first quarter of 2015 as commodity prices slightly improved during the second quarter of 2015 and the impact of lower CO_2 utilization from Jackson Dome. Including the cost of depreciation and amortization of capital expended at our CO_2 source fields and industrial sources, but excluding depreciation of our CO_2 pipelines, our cost of CO_2 was \$0.44 per Mcf and \$0.53 per Mcf during the second quarters of 2015 and 2014, respectively.

Non-tertiary lease operating expenses decreased 18% on an absolute-dollar basis and 10% on a per-BOE basis between the three months ended June 30, 2015 and 2014. Non-tertiary lease operating expenses decreased 21% on an absolute-dollar basis and 15% on a per-BOE basis between the six months ended June 30, 2015 and 2014. The decreases in both periods were primarily due to lower workover costs, repairs and maintenance costs, and lower third-party contractor and vendor expenses such as contract labor and chemical costs during the 2015 periods. On a sequential-quarter basis, our non-tertiary lease operating expenses decreased \$3.0 million (5%) on an absolute-dollar basis and \$0.41 (2%) on a per-BOE basis during the second quarter of 2015, as we have seen many of our costs decline, with the decrease in workover and labor costs the primary components of lease operating expense cost reductions.

Marketing and Plant Operating Expenses

Marketing and plant operating expenses primarily consist of amounts incurred relating to the marketing, processing, and transportation of oil and natural gas production, as well as expenses related to our Riley Ridge gas processing facility. Marketing and plant operating expenses decreased \$3.9 million (22%) and \$9.0 million (26%) during the three and six months ended June 30, 2015, respectively, compared to the same periods in 2014, primarily due to reductions in marketing, compression, and plant processing fees, as well as reductions related to the Riley Ridge gas processing facility, which is currently shut-in.

Taxes Other Than Income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income decreased \$17.3 million and \$36.6 million during the three and six months ended June 30, 2015, respectively, compared to the same periods in 2014. The levels of taxes other than income during most periods are generally aligned with fluctuations in oil and natural gas revenues. The decrease in 2015 is also attributable to severance tax reductions at Hastings Field and Oyster Bayou Field, which reduced severance taxes by approximately \$1.5 million and \$2.5 million during the three and six months ended June 30, 2015, respectively, related to state-approved enhanced oil recovery project exemptions that were approved in the second half of 2014 and reduce severance taxes for those fields for approximately the next seven years.

General and Administrative Expenses ("G&A")

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data and employees	2015	2014	2015	2014
Gross cash compensation and administrative costs	$ 84,365	$ 86,048	$ 179,645	$ 178,045
Gross stock-based compensation	8,684	11,131	19,743	22,357
Operator labor and overhead recovery charges	(41,427)	(42,933)	(83,555)	(86,073)
Capitalized exploration and development costs	(13,675)	(15,294)	(31,606)	(31,684)
Net G&A expense	$ 37,947	$ 38,952	$ 84,227	$ 82,645
G&A per BOE:				
Net administrative costs	$ 4.67	$ 4.49	$ 5.28	$ 4.96
Net stock-based compensation	0.99	1.19	1.01	1.17
Net G&A expense	$ 5.66	$ 5.68	$ 6.29	$ 6.13
Employees as of June 30	1,442	1,563		

Gross cash compensation and administrative costs on an absolute-dollar basis decreased $1.7 million (2%) and increased $1.6 million (1%) during the three and six months ended June 30, 2015, respectively, compared to those costs in the same periods in 2014. As part of our efforts to reduce overhead and operating costs in response to the significant decline in oil prices, we reduced our employee headcount in mid-2015 through an involuntary workforce reduction, which contributed to an overall headcount reduction of approximately 10% between January 1, 2015 and July 31, 2015. The severance payments associated with the workforce reduction were not material to the quarterly financial results. The decrease between the second quarter of 2014 and 2015 was primarily due to lower employee-related costs such as lower bonus accruals and long-term incentives resulting from the reduction in employee headcount during the second quarter of 2015 and a reduction in costs associated with our stock purchase plan following its termination at the end of the first quarter of 2015, partially offset by severance payments associated with the workforce reduction and higher employee-related insurance costs. The year-over-year increase was primarily due to higher professional service fees during the first quarter of 2015, partially offset by the net impact of the items previously mentioned above.

Net G&A expense on a per-BOE basis was relatively flat during the three months ended June 30, 2015, and increased 3% during the six months ended June 30, 2015, compared to levels in the same periods in 2014. The changes between the comparative three- and six-month periods were primarily based on the changes noted in gross cash compensation and administrative costs, lower gross stock-based compensation associated with the reduction in headcount, and lower total operator labor and overhead recovery charges and capitalized exploration and developments costs. For the remainder of 2015, we expect gross and net G&A expense to decrease further from the second quarter of 2015 levels once the full impact of the workforce reduction is realized.

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. Capitalized exploration and development costs decreased between both comparative periods, primarily due to decreased compensation costs subject to capitalization.

Interest and Financing Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data and interest rates	2015	2014	2015	2014
Cash interest expense	$ 46,322	$ 48,886	$ 92,609	$ 99,957
Noncash interest expense	2,279	3,459	4,500	6,978
Less: capitalized interest	(8,738)	(5,795)	(17,147)	(11,551)
Interest expense, net	$ 39,863	$ 46,550	$ 79,962	$ 95,384
Interest expense, net per BOE	$ 5.94	$ 6.79	$ 5.97	$ 7.07
Average debt outstanding	$ 3,583,316	$ 3,709,263	$ 3,599,527	$ 3,615,898
Average interest rate (1)	5.2%	5.3%	5.1%	5.5%

(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 six months ended June 30, 2015 than in the same periods in 2014. This decline was due to our April 2014 long-term debt refinancing, whereby we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022 to replace our $996.3 million of 8¼% Senior Subordinated Notes due 2020. Capitalized interest during the three and six months ended June 30, 2015 increased $2.9 million (51%) and $5.6 million (48%), respectively, compared to the same periods in 2014, primarily due to incremental capitalized interest on projects that qualify for interest capitalization.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data	2015	2014	2015	2014
Depletion and depreciation of oil and natural gas properties	$ 115,703	$ 115,458	$ 232,050	$ 223,617
Depletion and depreciation of CO_2 properties	6,546	7,342	14,758	15,300
Amortization of asset retirement obligations	2,386	2,197	4,713	4,398
Depreciation of pipelines, plants and other property and equipment	23,305	23,167	46,377	45,979
Total DD&A	$ 147,940	$ 148,164	$ 297,898	$ 289,294
DD&A per BOE:				
Oil and natural gas properties	$ 17.60	$ 17.17	$ 17.67	$ 16.90
CO_2, pipelines, plants and other property and equipment	4.45	4.45	4.56	4.55
Total DD&A cost per BOE	$ 22.05	$ 21.62	$ 22.23	$ 21.45
Write-down of oil and natural gas properties	$ 1,705,800	$ —	$ 1,852,000	$ —

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. DD&A of oil and natural gas properties and asset retirement obligations on an absolute-dollar basis was relatively flat and increased 4% during the three and six months ended June 30, 2015, respectively, compared to the same periods in 2014. On a per-BOE basis, DD&A of oil and natural gas properties and asset retirement obligations increased 3% and 5% during the three and six months ended June 30, 2015, respectively, compared to the same periods in 2014. These increases were primarily the result of a higher depletion rate per BOE relative to reserves. Given the full cost pool ceiling test write-down recognized during the three months ended June 30, 2015, we currently expect our DD&A rate in the third quarter of 2015 to decrease from the second quarter of 2015 rate by approximately $3 to $4 per BOE due to the write-down in depletable costs associated with our reserves base. However, the overall decrease in our third quarter DD&A rate will also be impacted by potential changes in reserve volumes, production, and future capital expenditure estimates, among other factors, and therefore, the actual decrease will most likely differ from this estimate.

Depletion and depreciation of our CO_2 properties, pipelines, plants and other property and equipment decreased 2% on an absolute-dollar basis and remained flat on a per-BOE basis during the three months ended June 30, 2015, compared to the same period in 2014, primarily due to a decrease in CO_2 production during the period, as we have been able to reduce the level of CO_2 production and injections without impacting our oil production.

Full Cost Pool Ceiling Test Write-Down

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the average first-day of the month oil and natural gas price for each month during a 12-month rolling period ended as of each quarterly reporting period. As a result of the precipitous decline in NYMEX oil prices since the fourth quarter of 2014, the rolling first-day-of-the-month average oil price for the preceding 12 months, after adjustments for market differentials by field, was $79.55 per Bbl for the first quarter of 2015 and $68.48 per Bbl for the second quarter of 2015. In addition, the first-day-of-the-month average natural gas price for the preceding 12 months, after adjustments for market differentials by field, was $3.95 per Mcf for the first quarter of 2015 and $3.74 per Mcf for the second quarter of 2015. The prices used for the second quarter of 2015 represent a decrease of 25% for crude oil and 13% for natural gas prices compared to adjusted prices used to calculate the December 31, 2014, full cost ceiling value. Because of the significant decrease in pricing during the fourth quarter of 2014 and its continued decline in the first and second quarters of 2015, we recognized full cost pool ceiling test write-downs of $1.7 billion and $0.2 billion during the three months ended June 30, 2015 and March 31, 2015, respectively. We currently expect that we will continue to record material write-downs in the third and fourth quarters of 2015 if oil and natural gas prices remain at or near late-July 2015 levels for the remainder of 2015, as the 12-month average price used in determining the full cost ceiling value would continue to decline during each rolling quarterly period in 2015, and also depending, in part, upon changes in proved oil and natural gas reserve volumes, future capital expenditures and operating costs. We currently estimate that the full cost ceiling test write-down in the third quarter of 2015 could be in a range of similar magnitude to the write-down recorded in the second quarter of 2015 depending, in part, upon changes in oil and natural gas prices, proved oil and natural gas reserve volumes, future capital expenditures and operating costs.

Impairment Assessment of Goodwill

We test goodwill for impairment annually during the fourth quarter; however, as a result of the relationship between our market capitalization and our book value of stockholders' equity and the sustained decrease in our share price, we also performed a goodwill impairment assessment as of June 30, 2015. Because our enterprise value (combined market capitalization plus a control premium of 10% and the fair value of our long-term debt) was below the combined book value of our stockholders' equity and long-term debt as of June 30, 2015, we were required to proceed to step two of the goodwill impairment test. Oil and natural gas reserves, which represent the most significant assets requiring valuation, were estimated using the expected present value of future cash flows method based on June 30, 2015, NYMEX oil and natural gas futures prices for the next five years, which ranged from approximately $60 per Bbl to $66 per Bbl for oil and $3 per MMBtu to $4 per MMBtu for natural gas, adjusted for current price differentials. Consistent with the results of our fourth quarter 2014 goodwill analysis, the implied fair value of goodwill calculated in this quantitative assessment exceeded the corresponding book value of goodwill. Therefore, we did not record any goodwill impairment during the second quarter of 2015, nor have we recorded a goodwill impairment historically. The cushion between the implied fair value of goodwill and book value of goodwill is due to our enterprise value declining at a slower rate than the decline in NYMEX oil futures prices, which were used in the step-two valuation of our oil reserves. A change in the assumptions noted above, including oil and natural gas futures prices, or a decrease in our enterprise value, could lead to an impairment of goodwill in future periods. For example, an approximate 5% increase in oil and natural gas futures prices as of

June 30, 2015, without a commensurate change in enterprise value or in other cash flow assumptions included in the goodwill impairment analysis, likely would have required a partial impairment of goodwill at June 30, 2015. Subsequent to June 30, 2015, our enterprise value declined at a rate in excess of the decline in NYMEX oil and natural gas futures prices. If this relationship continues until we perform our next goodwill impairment assessment as of September 30, 2015, we could incur a partial or full impairment of our $1.3 billion goodwill balance, the amount of the impairment (if any) depending upon further changes in our enterprise value, oil and natural gas futures prices, and other key assumptions.

Please refer to *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates – Impairment Assessment of Goodwill* in the Form 10-K for a complete discussion of the goodwill impairment test, including a discussion of relevant inputs, factors resulting in the deficit of enterprise value to book value, and the resulting cushion between implied fair value of goodwill and book value of goodwill.

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE amounts and tax rates	2015	2014	2015	2014
Current income tax expense (benefit)	$ (1,696)	$ (4,300)	$ (121)	$ 318
Deferred income tax expense (benefit)	(634,472)	(28,564)	(700,508)	1,611
Total income tax expense (benefit)	$ (636,168)	$ (32,864)	$ (700,629)	$ 1,929
Average income tax expense (benefit) per BOE	$ (94.84)	$ (4.79)	$ (52.28)	$ 0.14
Effective tax rate	35.6%	37.3%	35.8%	38.3%

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to our ordinary income or loss to calculate our estimated tax liability or benefit. As of June 30, 2015, we had $37.0 million of deferred tax assets associated with State of Louisiana net operating losses. As the result of a new tax law enacted in the State of Louisiana effective June 30, 2015, which limits a company's utilization of certain deductions, including our net operating loss carryforwards, we recognized a tax valuation allowance of $30.5 million to reduce the carrying value of our deferred tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized.

Our income taxes are based on estimated statutory rates of approximately 38% in 2015 and 2014. Our effective tax rate for the three and six months ended June 30, 2015, was lower than our estimated statutory rate, primarily due to the impact of the tax valuation allowance discussed above, which reduced the net deferred tax benefit recognized. Our effective tax rate for the three months ended June 30, 2014, was slightly below our estimated statutory rate, primarily due to the utilization of the domestic production activities deduction. The current tax benefit recorded during the three months ended June 30, 2014, was principally due to the loss on extinguishment of debt recognized for that quarter.

As of June 30, 2015, we had an estimated $45.2 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 2015 or future years. These enhanced oil recovery credits do not begin to expire until 2024. We currently do not expect to earn additional enhanced oil recovery credits during 2015.

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 significant individual components is discussed above.

	Three Months Ended June 30,		Six Months Ended June 30,	
Per-BOE data	2015	2014	2015	2014
Oil and natural gas revenues	$ 54.69	$ 95.86	$ 49.58	$ 94.96
Receipt (payment) on settlements of commodity derivatives	18.51	(7.32)	20.34	(5.73)
Lease operating expenses	(19.70)	(23.82)	(20.39)	(24.73)
Production and ad valorem taxes	(4.43)	(6.93)	(3.93)	(6.67)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.86)	(1.97)	(1.66)	(1.91)
Production netback	47.21	55.82	43.94	55.92
CO_2 and helium sales, net of operating and exploration expenses	0.93	0.90	0.91	0.87
General and administrative expenses	(5.66)	(5.68)	(6.29)	(6.13)
Interest expense, net	(5.94)	(6.79)	(5.97)	(7.07)
Other	0.97	1.58	0.77	1.10
Changes in assets and liabilities relating to operations	5.57	2.29	(1.52)	(4.31)
Cash flows from operations	43.08	48.12	31.84	40.38
DD&A	(22.05)	(21.62)	(22.23)	(21.45)
Write-down of oil and natural gas properties	(254.29)	—	(138.21)	—
Deferred income taxes	94.58	4.17	52.28	(0.12)
Loss on early extinguishment of debt	—	(16.62)	—	(8.44)
Noncash fair value adjustments on commodity derivatives	(25.80)	(18.18)	(17.79)	(12.91)
Other noncash items	(6.73)	(3.92)	0.36	2.77
Net income (loss)	$ (171.21)	$ (8.05)	$ (93.75)	$ 0.23

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, 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 prices and consequently in the prices received or demand for the Company's oil and natural gas; decisions as to production levels and/or pricing by OPEC in future periods; 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.

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 June 30, 2015, we had $350.0 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 June 30, 2015:

In thousands	2015	2017	2019	2021	2022	2023	Total
Variable rate debt:							
Bank Credit Facility (weighted average interest rate of 1.5% at June 30, 2015)	$ —	$ —	$ 350,000	$ —	$ —	$ —	$ 350,000
Fixed rate debt:							
6⅜% Senior Subordinated Notes due 2021	—	—	—	400,000	—	—	400,000
5½% Senior Subordinated Notes due 2022	—	—	—	—	1,250,000	—	1,250,000
4⅝% Senior Subordinated Notes due 2023	—	—	—	—	—	1,200,000	1,200,000
Other Subordinated Notes	484	2,250	—	—	—	—	2,734

See Note 2, *Long-Term Debt*, to the Unaudited Condensed Consolidated Financial Statements for details regarding our long-term debt.

Oil and Natural Gas Derivative Contracts

From time to time, we enter into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. These contracts have historically consisted of price floors, collars, three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. 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, financial strength, and expectation of future commodity prices. We have entered into a combination of enhanced swaps, collars, and three-way collars covering a total of 58,000 Bbls/d for the third quarter of 2015 and 38,000 Bbls/d for the fourth quarter of 2015. Roughly half of these 2015 derivative contracts are collars and three-way collars, so the variability in potential cash flows from these types of hedges exposes us to more downside price risk than fixed-price swaps. In addition, the sold puts that are part of our three-way collars and enhanced swaps limit the benefit our hedges provide us to the extent oil prices remain below the price of our sold puts. 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. 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 (or affiliates of such lenders). 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 treatment to our oil and natural gas derivative contracts. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At June 30, 2015, our commodity derivative contracts were recorded at their fair value, which was a net asset of $268.1 million, a $173.1 million decrease from the $441.2 million net asset recorded at March 31, 2015, and a $238.4 million decrease from the $506.5 million net asset recorded at December 31, 2014. Changes in this value are comprised of the expiration of commodity derivative contracts during 2015, new commodity derivative contracts entered into during 2015 for future periods, and to the changes in oil and natural gas futures prices between December 31, 2014 and June 30, 2015.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices and natural gas futures prices as of June 30, 2015, and assuming both a 10% increase and decrease thereon, we would expect to receive payments on our crude oil and natural gas derivative contracts as shown in the following table:

	Receipt / (Payment)	
In thousands	Crude Oil Derivative Contracts	Natural Gas Derivative Contracts
Based on:		
Futures prices as of June 30, 2015	$ 293,542	$ 1,610
10% increase in prices	259,652	1,180
10% decrease in prices	319,783	2,039

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.

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 our 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 management, including our Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2015, to ensure that information that is required to be disclosed in the reports the Company files and submits under the Securities Exchange Act of 1934 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 management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Evaluation of Changes in Internal Control over Financial Reporting. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the second quarter of fiscal 2015, 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

We are involved in various lawsuits, claims and 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 business or finances, litigation is subject to inherent uncertainties. Although a single or multiple adverse rulings or settlements could possibly have a material adverse effect on our business or finances, we only accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

In mid-2006, Denbury Onshore, LLC ("Denbury Onshore") purchased its original interest in the Delhi Field in northeastern Louisiana from NGS Sub Corp, ("NGS"), a subsidiary of Evolution Petroleum Corporation (together with its subsidiaries, "Evolution"). Under the purchase documents, Denbury Onshore committed to develop the enhanced production of a specific portion of Delhi Field, the Holt Bryant Unit, and after Denbury Onshore's receipt of a defined level of net cash flow from the Unit (as defined in the agreements, "payout"), to assign reversionary interests in the Unit back to NGS. After several years of dispute regarding payout calculations and related contractual terms, in December 2013, Evolution filed suit against Denbury Onshore in the 133rd Judicial District Court in Houston, Harris County, Texas for unspecified damages, alleging breach of contract, and requesting declaratory judgment as to various provisions of the purchase documents and accompanying oil and gas conveyancing instruments, including as to the method of calculation and timing of payout, the sharing of various costs, and the timing and extent of post-payout assignments from Denbury Onshore to NGS. In February 2014, we filed an answer and counterclaim denying Evolution's claims and alleging breach of contract by Evolution for failing to convey the full interest for which we paid and violating our preferential purchase rights, and asking for declaratory judgment as to purchase document terms, including those pertaining to the determination of payout, the assignment provisions of the documents, and cost sharing.

In March 2015, Evolution filed its First Amended Petition (subsequently further amended in June 2015), adding allegations of negligence and gross negligence against Denbury Onshore in connection with the June 2013 Delhi Field release of well fluids, the remediation of which was completed in the fourth quarter of 2013 (see Note 7, *Commitments and Contingencies* to our Unaudited Condensed Consolidated Financial Statements). Evolution claims for the first time in the First Amended Petition, that it estimates its damages attributable to its allegations in the case exceed $200 million. The First Amended Petition also adds a claim for unspecified punitive damages. There has only been limited discovery in the case to date, and Evolution has not specified the basis for the amount of its claimed damages estimate. The case is currently set for trial in April 2016. We believe that Evolution's claims with respect to this matter are without merit and intend to vigorously defend against them and pursue our rights under the purchase documents.

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. There have been no 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 second quarter of 2015:

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)]
April 2015	1,884	$ 8.80	—	$ 221.9
May 2015	5,701	7.61	—	221.9
June 2015	8,573	6.90	—	221.9
Total	16,158		—	

(1) Stock repurchases during the second quarter of 2015 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, the Company's Board of Directors approved a common share repurchase program for up to $500 million of Denbury's common stock. During 2012 and 2013, the Board of Directors increased the dollar amount of Denbury common shares that could be purchased under the program to an aggregate of up to $1.162 billion. The program has no pre-established ending date and may be suspended or discontinued at any time. In November 2014, the Company's Board of Directors suspended the common share repurchase program in light of commodity price uncertainty in order to protect our financial strength and preserve liquidity. However, the program allows its reinstatement 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 June 30, 2015, 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. As of June 30, 2015, an additional $221.9 million remains authorized for purchases of common stock under this repurchase program (but subject to the current suspension of this program by the Company's Board of Directors in November 2014).

Item 3. Defaults upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Denbury Resources Inc.

Item 6. Exhibits

Exhibit No.	Exhibit
10.1	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective as of May 19, 2015 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 22, 2015, 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.

Denbury Resources Inc.

SIGNATURES

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

	DENBURY RESOURCES INC.
August 6, 2015	/s/ Mark C. Allen
	Mark C. Allen Sr. Vice President and Chief Financial Officer
August 6, 2015	/s/ Alan Rhoades
	Alan Rhoades Vice President and Chief Accounting Officer

Denbury Resources Inc.

INDEX TO EXHIBITS

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101	Interactive Data Files.

Exhibit 31(a)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Phil Rykhoek, certify that:

1. I have reviewed this report on Form 10-Q of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

August 6, 2015

/s/ Phil Rykhoek

Phil Rykhoek
President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark C. Allen, certify that:

1. I have reviewed this report on Form 10-Q of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

August 6, 2015

/s/ Mark Allen

Mark C. Allen

Senior Vice President, Chief Financial Officer,
Treasurer, and Assistant Secretary

Exhibit 32

Certification of Chief Executive Officer and Chief Financial Officer
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying Annual Report on Form 10-Q for the quarter ended June 30, 2015 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Denbury.

Dated: August 6, 2015	/s/ Phil Rykhoek
	Phil Rykhoek
	President and Chief Executive Officer
Dated: August 6, 2015	/s/ Mark C. Allen
	Mark C. Allen
	Senior Vice President, Chief Financial Officer, Treasurer, and Assistant Secretary