DENBURY RESOURCES INC
Form 10-Q
August 09, 2018
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

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

For the quarterly period ended June 30, 2018
OR

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

For the transition period from _______ to ________

Commission file number: 001-12935
DENBURY RESOURCES INC.
(Exact name of registrant as specified in its charter)

Delaware	20-0467835
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5320 Legacy Drive, Plano, TX	75024
(Address of principal executive offices)	(Zip Code)

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

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

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

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

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

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

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

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

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

Class	Outstanding as of July 31, 2018
Common Stock, $.001 par value	460,637,322

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, 2018	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$116	$58
Accrued production receivable	163,719	146,334
Trade and other receivables, net	44,848	45,193
Other current assets	15,554	10,670
Total current assets	224,237	202,255
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	10,902,665	10,775,792
Unevaluated properties	965,553	951,397
CO_2 properties	1,192,731	1,191,058
Pipelines and plants	2,293,884	2,286,047
Other property and equipment	311,240	339,218
Less accumulated depletion, depreciation, amortization and impairment	(11,455,046)	(11,376,646)
Net property and equipment	4,211,027	4,166,866
Other assets	98,971	102,178
Total assets	$4,534,235	$4,471,299
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$195,143	$177,220
Oil and gas production payable	72,087	76,588
Derivative liabilities	145,254	99,061
Current maturities of long-term debt (including future interest payable of $84,932 and $75,347, respectively – see Note 4)	111,335	105,188
Total current liabilities	523,819	458,057
Long-term liabilities		
Long-term debt, net of current portion (including future interest payable of $207,659 and $241,472, respectively – see Note 4)	2,689,647	2,979,086
Asset retirement obligations	170,797	165,756
Derivative liabilities	10,704	—
Deferred tax liabilities, net	231,761	198,099
Other liabilities	21,862	22,136
Total long-term liabilities	3,124,771	3,365,077
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; 458,214,377 and 402,549,346 shares issued, respectively	458	403

Paid-in capital in excess of par	2,676,352	2,507,828
Accumulated deficit	(1,786,010)	(1,855,810)
Treasury stock, at cost, 806,318 and 457,041 shares, respectively	(5,155)	(4,256)
Total stockholders' equity	885,645	648,165
Total liabilities and stockholders' equity	$4,534,235	$4,471,299

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues and other income				
Oil, natural gas, and related product sales	$375,565	$250,880	$715,586	$517,058
CO_2 sales and transportation fees	6,715	6,555	14,267	11,943
Other income	4,783	3,749	10,444	7,637
Total revenues and other income	387,063	261,184	740,297	536,638
Expenses				
Lease operating expenses	120,384	111,318	238,740	225,158
Marketing and plant operating expenses	11,549	13,877	23,973	27,942
CO_2 discovery and operating expenses	500	513	962	1,106
Taxes other than income	27,234	20,175	54,553	42,615
General and administrative expenses	19,412	25,789	39,644	54,030
Interest, net of amounts capitalized of $8,851, $8,147, $17,303 and $12,801, respectively	16,208	24,061	33,447	51,239
Depletion, depreciation, and amortization	52,944	51,152	105,395	102,347
Commodity derivatives expense (income)	96,199	(10,373)	145,024	(34,975)
Other expenses	2,980	—	5,308	—
Total expenses	347,410	236,512	647,046	469,462
Income before income taxes	39,653	24,672	93,251	67,176
Income tax provision	9,431	10,273	23,451	31,247
Net income	$30,222	$14,399	$69,800	$35,929
Net income per common share				
Basic	$0.07	$0.04	$0.17	$0.09
Diluted	$0.07	$0.04	$0.15	$0.09
Weighted average common shares outstanding				
Basic	433,467	389,904	413,217	389,652
Diluted	457,165	391,827	454,466	392,414

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Six Months Ended June 30, 2018	2017
Cash flows from operating activities		
Net income	$69,800	$35,929
Adjustments to reconcile net income to cash flows from operating activities		
Depletion, depreciation, and amortization	105,395	102,347
Deferred income taxes	25,237	51,147
Stock-based compensation	5,152	8,941
Commodity derivatives expense (income)	145,024	(34,975)
Payment on settlements of commodity derivatives	(88,127)	(38,707)
Debt issuance costs and discounts	2,268	3,344
Other, net	(5,107)	(1,006)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	(17,385)	21,114
Trade and other receivables	(320)	(17,916)
Other current and long-term assets	(5,627)	(10,225)
Accounts payable and accrued liabilities	14,999	(26,611)
Oil and natural gas production payable	(4,501)	(12,652)
Other liabilities	(1,182)	(3,522)
Net cash provided by operating activities	245,626	77,208
Cash flows from investing activities		
Oil and natural gas capital expenditures	(134,458)	(129,884)
Acquisitions of oil and natural gas properties	—	(89,208)
Pipelines and plants capital expenditures	(7,882)	(634)
Net proceeds from sales of oil and natural gas properties and equipment	2,077	725
Other	6,131	(1,294)
Net cash used in investing activities	(134,132)	(220,295)
Cash flows from financing activities		
Bank repayments	(1,153,653)	(796,000)
Bank borrowings	1,093,653	985,000
Interest payments treated as a reduction of debt	(37,233)	(25,139)
Pipeline financing and capital lease debt repayments	(12,625)	(13,728)
Other	(628)	(4,289)
Net cash provided by (used in) financing activities	(110,486)	145,844
Net increase in cash, cash equivalents, and restricted cash	1,008	2,757
Cash, cash equivalents, and restricted cash at beginning of period	40,614	40,905
Cash, cash equivalents, and restricted cash at end of period	$41,622	$43,662

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Denbury Resources Inc.
Unaudited Condensed Consolidated Statement of Changes in Stockholders' Equity
(Dollar amounts in thousands)

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Treasury Stock (at cost)		Total Equity
	Shares	Amount			Shares	Amount	
Balance – December 31, 2017	402,549,346	$ 403	$2,507,828	$(1,855,810)	457,041	$(4,256)	$648,165
Issued or purchased pursuant to stock compensation plans	415,032	—	—	—	—	—	—
Issued pursuant to notes conversion	55,249,999	55	161,995	—	—	—	162,050
Stock-based compensation	—	—	6,529	—	—	—	6,529
Tax withholding – stock compensation	—	—	—	—	349,277	(899)	(899)
Net income	—	—	—	69,800	—	—	69,800
Balance – June 30, 2018	458,214,377	$ 458	$2,676,352	$(1,786,010)	806,318	$(5,155)	$885,645

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is 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, 2017 (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, 2018, our consolidated results of operations for the three and six months ended June 30, 2018 and 2017, our consolidated cash flows for the six months ended June 30, 2018 and 2017, and our consolidated statement of changes in stockholders' equity for the six months ended June 30, 2018.

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.

Cash, Cash Equivalents, and Restricted Cash

The following table provides a reconciliation of cash, cash equivalents, and restricted cash as reported within the Unaudited Condensed Consolidated Balance Sheets to "Cash, cash equivalents, and restricted cash at end of period" as reported within the Unaudited Condensed Consolidated Statements of Cash Flows:

In thousands	June 30, 2018	December 31, 2017
Cash and cash equivalents	$116	$ 58
Restricted cash included in Other assets	41,506	40,556
Total cash, cash equivalents, and restricted cash shown in the Unaudited Condensed Consolidated Statements of Cash Flows	$41,622	$ 40,614

Amounts included in restricted cash included in “Other assets” in the accompanying Unaudited Condensed Consolidated Balance Sheets represent escrow accounts that are legally restricted for certain of our asset retirement obligations.

Net Income per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of nonvested restricted stock, nonvested performance-based equity awards, and shares into which our previously-outstanding convertible senior notes were convertible.

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Notes to Unaudited Condensed Consolidated Financial Statements

The following table sets forth the reconciliations of net income and weighted average shares used for purposes of calculating the basic and diluted net income per common share for the periods indicated:

In thousands	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Numerator				
Net income – basic	$30,222	$14,399	$69,800	$35,929
Effect of potentially dilutive securities				
Interest on convertible senior notes	130	—	539	—
Net income – diluted	$30,352	$14,399	$70,339	$35,929
Denominator				
Weighted average common shares outstanding – basic	433,467	389,904	413,217	389,652
Effect of potentially dilutive securities				
Restricted stock and performance-based equity awards	8,586	1,923	6,877	2,762
Convertible senior notes	15,112	—	34,372	—
Weighted average common shares outstanding – diluted	457,165	391,827	454,466	392,414

Basic weighted average common shares exclude shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although time-vesting restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares during the three and six months ended June 30, 2018 and 2017, the nonvested restricted stock 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, and for the shares underlying the previously-outstanding convertible senior notes as if the convertible senior notes were converted at the beginning of the 2018 period. In April and May 2018, all outstanding convertible senior notes converted into shares of Denbury common stock, resulting in the issuance of 55.2 million shares of our common stock upon conversion. These shares have been included in basic weighted average common shares outstanding beginning on the date of conversion. See Note 4, Long-Term Debt, for further discussion.

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

In thousands	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Stock appreciation rights	2,827	4,785	2,891	4,914
Restricted stock and performance-based equity awards	179	7,655	305	4,442

Recent Accounting Pronouncements

Recently Adopted

Cash Flows. In November 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-18, Statement of Cash Flows ("ASU 2016-18"). ASU 2016-18 addresses the diversity that exists in the classification and presentation of changes in restricted cash on the statement of cash flows, and requires that a statement of cash flows explain the change in total cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, entities will no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents in the statement of cash flows. Effective January 1, 2018, we adopted ASU 2016-18, which has been applied retrospectively for all comparative periods presented. Accordingly, restricted cash associated with our escrow accounts of $40.6 million and $39.3 million for the six month periods ended June 30, 2018 and 2017, respectively, have been included in "Cash, cash equivalents, and restricted cash at beginning of period" on our Unaudited Condensed Consolidated Statements of Cash Flows and $40.2 million included in "Cash, cash equivalents, and restricted cash at end of period" for the six-month period ended June 30, 2017. The adoption of ASU 2016-18 did not have an impact on our consolidated balance sheets or results of operations.

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. In March, April and May 2016, the FASB issued four additional ASUs which primarily clarified the implementation guidance on principal versus agent considerations, performance obligations and licensing, collectibility, presentation of sales taxes and other similar taxes collected from customers, and non-cash consideration. Effective January 1, 2018, we adopted ASU 2014-09 using the modified retrospective method. The adoption of ASU 2014-09 did not have an impact on our consolidated financial statements, but required enhanced footnote disclosures. See Note 2, Revenue Recognition, for additional information.

Not Yet Adopted

Leases. In February 2016, the FASB issued ASU 2016-02, Leases ("ASU 2016-02"). ASU 2016-02 amends the guidance for lease accounting to require lease assets and liabilities to be recognized on the balance sheet, along with additional disclosures regarding key leasing arrangements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, and early adoption is permitted. Entities must adopt the standard using a modified retrospective transition and apply the guidance to the earliest comparative period presented, with certain practical expedients that entities may elect to apply. In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842) – Land Easement Practical Expedient for Transition to Topic 842, which provides an optional practical expedient to existing or expired land easements that were not previously accounted for as leases under Topic 842, which permits a company to evaluate only new or modified land easements under the new guidance. We are currently evaluating our lease agreements and implementing a software system to summarize the key contract terms and financial information associated with each lease agreement, in order to assess the impact the adoption of ASU 2016-02 and ASU 2018-01 will have on our consolidated financial statements.

Note 2. Revenue Recognition

We record revenue in accordance with FASB Accounting Standards Codification ("ASC") Topic 606, Revenue from Contracts with Customers, which we adopted on January 1, 2018, and applied to all existing contracts using the modified retrospective method. The core principle of FASB ASC Topic 606 is that an entity should recognize revenue for the transfer of goods or services equal to the amount of consideration that it expects to be entitled to receive for those goods or services. This principle is achieved through applying a five-step process for customer contract revenue recognition:

•Identify the contract or contracts with a customer – We derive the majority of our revenues from oil and natural gas sales contracts and CO_2 sales and transportation contracts. The contracts specify each party's rights regarding the goods or services to be transferred and contain commercial substance as they impact our financial statements. A high percentage of our receivables balance is current, and we have not historically entered into contracts with counterparties that pose a credit risk without requiring adequate economic protection to ensure collection.

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•Identify the performance obligations in the contract – Each of our revenue contracts specify a volume per day, or production from a lease designated in the contract (a distinct good), to be delivered at the delivery point over the term of the contract (the identified performance obligation). The customer takes delivery and physical possession of the product at the delivery point, which generally is also the point at which title transfers and the customer obtains the risks and rewards of ownership (the identified performance obligation is satisfied).

•Determine the transaction price – Typically, our oil and natural gas contracts define the price as a formula price based on the average market price, as specified on set dates each month, for the specific commodity during the month of delivery. Certain of our CO_2 contracts define the price as a fixed contractual price adjusted to an inflation index to reflect market pricing. Given the industry practice to invoice customers the month following the month of delivery and our high probability of collection of payment, no significant financing component is included in our contracts.

•Allocate the transaction price to the performance obligations in the contract – The majority of our revenue contracts are short-term, with terms of one year or less, to which we have applied the practical expedient permitted under the standard eliminating the requirement to disclose the transaction price allocated to remaining performance obligations. In limited instances, we have revenue contracts with terms greater than one year; however, the future delivery volumes are wholly unsatisfied as they represent separate performance obligations with variable consideration. We utilized the practical expedient which eliminates the requirement to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to wholly unsatisfied performance obligations. As there is only one performance obligation associated with our contracts, no allocation of the transaction price is necessary.

•Recognize revenue when, or as, we satisfy a performance obligation – Once we have delivered the volume of commodity to the delivery point and the customer takes delivery and possession, we are entitled to payment and we invoice the customer for such delivered production. Payment under most oil and CO_2 contracts is made within a month following product delivery and for natural gas and NGL contracts is generally made within two months following delivery. Timing of revenue recognition may differ from the timing of invoicing to customers; however, as the right to consideration after delivery is unconditional based on only the passage of time before payment of the consideration is due, upon delivery we record a receivable in “Accrued production receivable” in our Unaudited Condensed Consolidated Balance Sheets, which was $163.7 million and $146.3 million as of June 30, 2018 and December 31, 2017, respectively.

Disaggregation of Revenue

The following table summarizes our revenues by product type for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2018	2017	2018	2017
Oil sales	$373,286	$248,317	$710,692	$512,291
Natural gas sales	2,279	2,563	4,894	4,767
CO_2 sales and transportation fees	6,715	6,555	14,267	11,943
Total revenues	$382,280	$257,435	$729,853	$529,001

Note 3. Assets Held for Sale

We began actively marketing for sale certain non-productive surface acreage in the Houston area in July 2017. As of June 30, 2018, the carrying value of the land held for sale was $33.0 million, which is included in “Other property and equipment” on our Unaudited Condensed Consolidated Balance Sheets.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 4. Long-Term Debt

The table below reflects long-term debt and capital lease obligations outstanding as of the dates indicated:

In thousands	June 30, 2018	December 31, 2017
Senior Secured Bank Credit Agreement	$415,000	$475,000
9% Senior Secured Second Lien Notes due 2021	614,919	614,919
9¼% Senior Secured Second Lien Notes due 2022	455,668	381,568
3½% Convertible Senior Notes due 2024	—	84,650
6 % Senior Subordinated Notes due 2021	203,545	215,144
5½% Senior Subordinated Notes due 2022	314,662	408,882
4 % Senior Subordinated Notes due 2023	307,978	376,501
Pipeline financings	186,525	192,429
Capital lease obligations	15,906	26,298
Total debt principal balance	2,514,203	2,775,391
Future interest payable[(1)]	292,591	316,818
Debt issuance costs	(5,812)	(7,935)
Total debt, net of debt issuance costs	2,800,982	3,084,274
Less: current maturities of long-term debt[(1)]	(111,335)	(105,188)
Long-term debt and capital lease obligations	$2,689,647	$2,979,086

(1) Future interest payable represents most of the interest due over the terms of our 9% Senior Secured Second Lien Notes due 2021 (the “2021 Senior Secured Notes”), 9¼% Senior Secured Second Lien Notes due 2022 (the “2022 Senior Secured Notes”), and to a lesser extent our previously outstanding 3½% Convertible Senior Notes due 2024 (the “2024 Convertible Senior Notes”) and has been accounted for as debt in accordance with FASC 470-60, Troubled Debt Restructuring by Debtors. Our current maturities of long-term debt as of June 30, 2018 include $84.9 million of future interest payable related to the 2021 Senior Secured Notes and 2022 Senior Secured Notes that is due within the next twelve months. See January 2018 Note Exchanges below for further discussion.

The ultimate parent company in our corporate structure, Denbury Resources Inc. (“DRI”), is the sole issuer of all of our outstanding senior secured and 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 such notes are minor subsidiaries.

Senior Secured 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 (as amended, the “Bank Credit Agreement”). The Bank Credit Agreement is a senior secured revolving credit facility with a maturity date of December 9, 2019 and semiannual borrowing base redeterminations in May and November of each year. As part of our spring 2018 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $1.05 billion, with the next such redetermination being scheduled for November 2018. If our outstanding debt under the Bank Credit Agreement were to ever exceed the borrowing base, we would be required to repay the excess amount over a period not to exceed six months. The weighted average interest rate on borrowings outstanding under the Bank Credit Agreement was 4.7% as of June 30, 2018. We incur a commitment fee of 0.50% on the undrawn portion of the aggregate lender commitments under the Bank Credit Agreement.

At June 30, 2018, the Bank Credit Agreement contained certain financial performance covenants through the maturity of the facility, including the following:

- A consolidated senior secured debt to consolidated EBITDAX covenant, with such ratio not to exceed 2.5 to 1.0. Currently, only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio;

- A minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0; and
- A requirement to maintain a current ratio of 1.0 to 1.0.

The above description of our Bank Credit Agreement is qualified by the express language and defined terms contained in the Bank Credit Agreement and the amendments thereto, each of which are filed as exhibits to our periodic reports filed with the SEC.

January 2018 Note Exchanges

During January 2018, we closed transactions to exchange a total of $174.3 million aggregate principal amount of our then existing senior subordinated notes for $74.1 million aggregate principal amount of new 2022 Senior Secured Notes and $59.4 million aggregate principal amount of new 5% Convertible Senior Notes due 2023 (the "2023 Convertible Senior Notes"), resulting in a net reduction in our debt principal from these exchanges of $40.8 million. The exchanged notes consisted of $11.6 million aggregate principal amount of our 6 % Senior Subordinated Notes due 2021, $94.2 million aggregate principal amount of our 5½% Senior Subordinated Notes due 2022 and $68.5 million aggregate principal amount of our 4 % Senior Subordinated Notes due 2023.

In accordance with FASC 470-60, the exchange was accounted for as a troubled debt restructuring due to the level of concession provided by our senior subordinated note holders. Under this guidance, future interest applicable to the new 2022 Senior Secured Notes and 2023 Convertible Senior Notes was recorded as debt up to the point that the principal and future interest of the new notes was equal to the principal amount of the extinguished notes, rather than recognizing a gain on extinguishment for this amount. In May 2018, the debt principal balance and future interest applicable to the 2023 Convertible Senior Notes were reclassified to "Paid-in capital in excess of par" and "Common stock" in our Unaudited Condensed Consolidated Balance Sheets following the conversion of the notes into shares of Denbury common stock (see Conversions of 2023 and 2024 Convertible Senior Notes below for further discussion). As of June 30, 2018, $22.1 million of future interest on the new 2022 Senior Secured Notes was recorded as debt, which will be reduced as semiannual interest payments are made, with the remaining $3.6 million of future interest to be recognized as interest expense over the term of the notes. Therefore, future interest expense reflected in our Unaudited Condensed Consolidated Statements of Operations on the new 2022 Senior Secured Notes will be significantly lower than the actual cash interest payments.

9¼% Senior Secured Second Lien Notes due 2022

In January 2018, we issued $74.1 million of 2022 Senior Secured Notes, which principal amount is in addition to the $381.6 million of 2022 Senior Secured Notes issued during December 2017. All $455.7 million of the 2022 Senior Secured Notes were issued in connection with exchanges with a limited number of holders of the Company's existing senior subordinated notes in December 2017 and January 2018 (see January 2018 Note Exchanges above). The 2022 Senior Secured Notes bear interest at 9.25% per annum, with interest payable semiannually in arrears on March 31 and September 30 of each year, and mature on March 31, 2022. We may redeem the 2022 Senior Secured Notes in whole or in part at our option beginning March 31, 2019, at a redemption price of 109.25% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture governing the 2022 Senior Secured Notes. Prior to March 31, 2019, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2022 Senior Secured Notes at a price of 109.25% of par with the proceeds of certain equity offerings. In addition, at any time prior to March 31, 2019, we may redeem the 2022 Senior Secured Notes in whole or in part at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 2022 Senior Secured Notes are not subject to any sinking fund requirements.

The 2022 Senior Secured Notes are guaranteed jointly and severally by our subsidiaries representing substantially all of our assets, operations and income and are secured by second-priority liens on substantially all of the assets that secure the Bank Credit Agreement, which second-priority liens are contractually subordinated to liens that secure our Bank Credit Agreement and any future additional priority lien debt.

Conversions of 2023 and 2024 Convertible Senior Notes

During the second quarter of 2018, holders of all $59.4 million aggregate principal amount outstanding of our 2023 Convertible Senior Notes and $84.7 million aggregate outstanding principal amount of our 2024 Convertible Senior Notes converted their notes into shares of Denbury common stock, at the rates specified in the indentures for these notes, resulting in the issuance of 55.2 million shares of our common stock upon conversion. The debt principal balances and future interest treated as debt applicable to the 2023 Convertible Senior Notes and 2024 Convertible Senior Notes, totaling $162.1 million, were reclassified to "Paid-in capital in excess of par" and "Common stock" in our Unaudited Condensed Consolidated Balance Sheets upon the conversion of the notes into shares of Denbury common stock. As of April 18, 2018 and May 30, 2018, there were no remaining 2024 Convertible Senior Notes and 2023 Convertible Senior Notes outstanding, respectively.

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.

Historically, we have entered 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 and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. 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 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, 2018, 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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Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

The following table summarizes our commodity derivative contracts as of June 30, 2018, none of which are classified as hedging instruments in accordance with the FASC Derivatives and Hedging topic:

Months	Index Price	Volume (Barrels per day)	Contract Prices ($/Bbl)				
			Range[(1)]	Weighted Average Price			
				Swap	Sold Put	Floor	Ceiling
Oil Contracts:							
2018 Fixed-Price Swaps							
July – Dec	NYMEX	20,500	$50.00–56.65	$51.69	$—	$—	$—
July – Dec	Argus LLS	5,000	60.10–60.25	60.18	—	—	—
2018 Three-Way Collars[(2)]							
July – Dec	NYMEX	15,000	$45.00–56.60	$—	$36.50	$46.50	$53.88
2019 Fixed-Price Swaps							
Jan – June	NYMEX	3,500	$59.00–59.10	$59.05	$—	$—	$—
2019 Three-Way Collars[(2)]							
Jan – June	NYMEX	16,500	$55.00–75.45	$—	$48.45	$56.45	$69.88
July – Dec	NYMEX	20,000	55.00–75.45	—	48.20	56.20	69.04
Jan – Dec	Argus LLS	3,000	62.00–78.90	—	54.00	62.00	78.50

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

(2) 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 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). Our costless collars and the sold put features of our 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. As of June 30, 2018, instruments in this category include non-exchange-traded three-way collars that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). The valuation models utilized for 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 $225 thousand in the fair value of these instruments as of June 30, 2018.

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, 2018				
Liabilities				
Oil derivative contracts – current	$ —	$ (144,554)	$ (700)	$ (145,254)
Oil derivative contracts – long-term	—	(10,236)	(468)	(10,704)
Total Liabilities	$ —	$ (154,790)	$ (1,168)	$ (155,958)
December 31, 2017				
Liabilities				
Oil derivative contracts – current	$ —	$ (99,061)	$ —	$ (99,061)
Total Liabilities	$ —	$ (99,061)	$ —	$ (99,061)

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, 2018 and 2017:

In thousands	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Fair value of Level 3 instruments, beginning of period	$—	$ 91	$—	$ (526)
Fair value gains (losses) on commodity derivatives	(1,168)	8	(1,168)	625
Fair value of Level 3 instruments, end of period	$ (1,168)	$ 99	$ (1,168)	$ 99
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	$ (1,168)	$ 8	$ (1,168)	$ 245

We utilize an income approach to value our Level 3 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 6/30/2018 (in thousands)	Valuation Technique	Unobservable Input	Volatility Range
Oil derivative contracts	$ (1,168)	Discounted cash flow / Black-Scholes	Volatility of Light Louisiana Sweet for settlement periods beginning after June 30, 2018	22.3% – 29.2%

Other Fair Value Measurements

The carrying value of our 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 the fair value of our fixed-rate long-term debt using observable market data. The fair values of our senior secured second lien notes, convertible senior notes, and senior subordinated notes are based on quoted market prices, which are considered Level 1 measurements under the fair value hierarchy. The estimated fair value of the principal amount of our debt as of June 30, 2018 and December 31, 2017, excluding pipeline financing and capital lease obligations, was $2,299.1 million and $2,260.6 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

Litigation

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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Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC. The helium supply contract provides for the delivery of a minimum contracted quantity of helium, subject to adjustment after startup of the Riley Ridge gas processing facility, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are specified in the contract at up to \$8.0 million per contract year and are capped at an aggregate of \$46.0 million over the term of the contract. As the gas processing facility has been shut-in since mid-2014, we have not been able to supply helium under the helium supply contract. APMTG Helium, LLC filed a case in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, claiming multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company's position is that our contractual obligations are excused by virtue of events that fall within the force majeure provisions in the helium supply contract. The evidentiary phase of the trial concluded on November 29, 2017. The parties submitted written closing briefs and rebuttal briefs to the District Court during February and April of 2018. We currently expect a ruling from the District Court to be made during 2018. The Company plans to continue to vigorously defend its position, but we are unable to predict at this time the outcome of this dispute.

Note 8. Subsequent Event

Employee Equity Award Grants

On July 16, 2018, the Compensation Committee of our Board of Directors granted customary long-term equity incentive awards covering 4,390,002 shares of restricted stock to certain employees under our 2004 Omnibus Stock and Incentive Plan. The closing price of Denbury's common stock on July 16, 2018 was \$4.64 per share. The awards generally vest one-third per year over a three-year period.

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, 2017 (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 the Form 10-K, 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 Impact on Our Business. Our financial results are significantly impacted by changes in oil prices, as 97% of our production is oil. Over the last year, NYMEX oil prices have gradually improved from around $50 per Bbl in August 2017, to around $70 per Bbl at the end of July 2018, which are considerably higher than those experienced in 2015 and 2016, when oil prices generally ranged between $40-$50 per Bbl. NYMEX oil prices averaged approximately $68 per Bbl in the second quarter of 2018 compared to approximately $48 per Bbl in the second quarter of 2017 and $63 per Bbl in the first quarter of 2018. Increases in oil prices impact all aspects of our business; most notably our cash flow from operations, revenues, and capital allocation and budgeting decisions. Our 2018 capital spending has been budgeted at approximately $300 million to $325 million, excluding capitalized interest and acquisitions, roughly a 30% increase over 2017 capital spending levels. Utilizing first half 2018 realized oil prices and futures oil prices for the remainder of 2018, we currently project a level of cash flow that would more than fully fund our development capital spending plans, with incremental cash flow currently expected to be utilized to reduce debt. At this capital spending level, we currently anticipate our 2018 production to average between 60,000 and 64,000 BOE/d.

Operating Highlights. We recognized net income of $30.2 million, or $0.07 per diluted common share, during the second quarter of 2018, compared to net income of $14.4 million, or $0.04 per diluted common share, during the second quarter of 2017. The primary drivers of our change in operating results between the comparative second quarters of 2018 and 2017 were the following:

- Oil and natural gas revenues in the second quarter of 2018 improved by $124.7 million, or 50%, principally driven by a 45% improvement in realized oil prices, along with a 4% increase in average daily production volumes. Our net realized oil price relative to NYMEX prices improved by $1.55 per Bbl from the prior-year period to $0.39 per Bbl above NYMEX.
- Commodity derivatives expense increased by $106.6 million ($96.2 million of expense in the current-year period compared to $10.4 million of income in the prior-year period). This increase in expense was the result of losses from noncash fair value adjustments between the periods of $63.6 million and a $43.0 million increase in payments on derivative settlements.

- Lease operating expenses increased $9.1 million (8%), or 4% on a per-BOE basis, primarily impacted by operating expenses related to our non-operated working interest in Salt Creek Field, which was acquired in late June 2017, as well as higher CO_2 expense due to increases in oil prices to which CO_2 prices are tied, and an increase in power and fuel costs, partially offset by lower workover expenses during the current year.
- General and administrative expenses decreased $6.4 million, primarily as a result of lower employee-related costs due to a workforce reduction in August 2017.
- Interest expense, net, decreased on a GAAP basis by $7.9 million primarily due to debt exchange transactions completed during December 2017 and January 2018, whereby most of the future interest associated with the new notes was recorded as debt, as well as the conversion during the second quarter of 2018 of all convertible senior notes issued in December and January into shares of Denbury common stock. See Results of Operations – Interest and Financing Expenses for further discussion.

We generated $154.0 million of cash flow from operating activities in the second quarter of 2018, an increase of $101.1 million from the second quarter of 2017 levels. The increase in cash flow from operations was due primarily to higher oil and natural gas revenues of $124.7 million and favorable working capital changes of $32.1 million ($19.8 million of cash inflows during the second quarter of 2018 compared to $12.3 million of cash outflows during the second quarter of 2017), partially offset by an increase in derivative settlement payments of $43.0 million.

Recent Debt Reduction Transactions. We reduced our debt principal by $328.5 million between December 2017 and May 2018 through a series of exchange transactions and related debt conversions as follows:

- During December 2017, we reduced debt principal by $143.6 million through privately negotiated transactions, in which institutional holders exchanged $609.8 million aggregate principal amount of our subordinated debt for:
  - $381.6 million aggregate principal amount of 9¼% Senior Secured Second Lien Notes due 2022 (the "2022 Senior Secured Notes") and
  - $84.7 million aggregate principal amount of 3½% Convertible Senior Notes due 2024 (the "2024 Convertible Senior Notes")

- During January 2018, we reduced debt principal by $40.8 million through additional exchange transactions, in which institutional holders exchanged $174.3 million aggregate principal amount of our subordinated debt for:
  - $74.1 million aggregate principal amount of 2022 Senior Secured Notes and
  - $59.4 million aggregate principal amount of 5% Convertible Senior Notes due 2023 (the "2023 Convertible Senior Notes")

- In April and May 2018, we reduced debt principal by $144.1 million when holders of all outstanding 2024 Convertible Senior Notes and 2023 Convertible Senior Notes, issued in the exchanges above, converted their notes into shares of Denbury common stock, at rates specified in the indentures for the notes, which resulted in the issuance of 55.2 million shares of our common stock upon conversion. As of April 18, 2018 and May 30, 2018, there were no remaining 2024 Convertible Senior Notes or 2023 Convertible Senior Notes outstanding, respectively. The conversion of these notes saves the Company annual cash interest payments of $5.9 million.

Sanctioning of Enhanced Oil Recovery Development at Cedar Creek Anticline. In June 2018, we announced the sanctioning of the CO_2 enhanced oil recovery development project at Cedar Creek Anticline. The capital outlay required to bring the initial phase of the project to first tertiary production is currently estimated at $250 million over the next four years, which includes $150 million for a 110-mile extension of the Greencore CO_2 pipeline from Bell Creek Field and $100 million for development in the Red River formation at East Lookout Butte and Cedar Hills South fields. First tertiary production is currently expected in late 2021 or early 2022.

Exploitation Drilling Update. Following the success of our first exploitation horizontal well in the Mission Canyon interval at Cedar Creek Anticline at the end of 2017, we successfully completed two additional Mission Canyon wells in the first half of 2018, one near the end of the first quarter and another early in the second quarter of 2018. These first three wells had a combined 30-day initial production rate of over 3,000 gross barrels of oil per day. Drilling in the Mission Canyon interval paused throughout the second quarter to comply with Bureau of Land Management and state wildlife stipulations, with the next well expected to be spud in late-August or early-September 2018. During the second quarter of 2018, we successfully completed our first well in the Perry Sand interval at Tinsley Field in Mississippi, with better than expected deliverability and an initial 30-day gross production rate (constrained by artificial lift equipment) of approximately 150 barrels of oil per day. For 2018, we have allocated $30 to $40 million of our 2018 capital budget to exploitation drilling across our company-wide portfolio of assets. We have seven additional Mission Canyon wells planned for the second half of 2018, and we plan to drill a well in the Powder River Basin at Hartzog Draw Field to test the prospectivity of deeper intervals on our acreage, which is held by Hartzog Draw unit production, as well as testing the Cotton Valley interval at Tinsley Field.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flow from operations and availability of borrowing capacity under our senior secured bank credit facility. For the six months ended June 30, 2018, we generated cash flow from operations of $245.6 million, after giving effect to $14.0 million of cash outflows for working capital changes, which were impacted primarily by increasing revenues during 2018 due to rising oil prices.

As of June 30, 2018, we had $415.0 million drawn on our senior secured bank credit facility, compared to $475.0 million of borrowings outstanding as of December 31, 2017 and $450.0 million as of March 31, 2018. As of June 30, 2018, we therefore had $572.8 million of borrowing base availability, after consideration of $62.2 million of outstanding letters of credit.

We have historically tried to limit our development capital spending to be roughly the same or less than our cash flow from operations, and we currently expect that 2018 cash flow from operations will well exceed our planned $300 million to $325 million of development capital expenditures for the year. We believe the $572.8 million of liquidity available under our bank credit facility at June 30, 2018 is sufficient to cover any excess working capital needs or any foreseeable cash flow shortfall between our cash flow from operations and capital spending. The Company may also enhance its available liquidity or raise funds through asset sales, joint ventures, or issuance of debt and/or equity. For example, the Company has been engaged in two asset sale processes. In mid-2017, we began to actively market for sale certain non-producing surface acreage in the Houston area. The acreage contains numerous parcels, and we currently anticipate that a portion of these sales will occur in 2018, with the remainder extending into 2019. Further, in February 2018, we initiated a sale process for our mature EOR properties located in Mississippi and Louisiana and Citronelle Field located in Alabama. In aggregate, these fields accounted for 12% of our second quarter 2018 production and approximately 7% of our 2017 year-end proved reserves. The success, timing and outcome of these processes cannot be predicted at this time, but their successful completion could provide funds to pay down debt or add liquidity for financial or operational uses.

We have reduced our outstanding debt principal by approximately $1.1 billion between December 31, 2014 and June 30, 2018, primarily through debt exchanges, opportunistic open market debt repurchases, and the conversion in the second quarter of 2018 of all of our outstanding convertible senior notes into common stock. The improvement in oil prices, our business and the market price of our debt securities has reduced our opportunity for additional exchange transactions, but we remain focused on continued efforts to improve the Company's balance sheet, both in terms of overall debt reduction and extension of debt maturities. We also remain keenly focused on continuing to improve our overall leverage metrics. Our leverage metrics have improved considerably over the past year, due primarily to our cost reduction efforts, continued improvement in oil prices and our overall reduction in debt. In conjunction with our efforts to improve the Company's balance sheet, we may have discussions with bondholders from time to time regarding potential debt reduction or maturity extension transactions of various types. Potential transactions could include purchases of our debt in the open market, debt exchange offers, cash tenders for our debt, possible debt reduction with proceeds of issuances of equity or debt, or use of proceeds from asset sales, joint ventures or other cash-generating activities for debt reduction.

Senior Secured 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 (as amended, the "Bank Credit Agreement"). As part of our spring 2018 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $1.05 billion, with the next such redetermination scheduled for November 2018.

At June 30, 2018, the Bank Credit Agreement contained certain financial performance covenants through the maturity of the facility, including the following:

- A consolidated senior secured debt to consolidated EBITDAX covenant, with such ratio not to exceed 2.5 to 1.0. Currently, only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio;
- A minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0; and
- A requirement to maintain a current ratio of 1.0 to 1.0.

Under these financial performance covenant calculations, as of June 30, 2018, our ratio of consolidated senior secured debt to consolidated EBITDAX was 0.75 to 1.0 (with a maximum permitted ratio of 2.5 to 1.0), our ratio of consolidated EBITDAX to consolidated interest charges was 3.04 to 1.0 (with a required ratio of not less than 1.25 to 1.0), and our current ratio was 2.98 to 1.0 (with a required ratio of not less than 1.0 to 1.0). Based upon our currently forecasted levels of production and costs, hedges in place as of August 6, 2018, and current oil commodity futures prices, we currently anticipate continuing to be in compliance with our financial performance covenants during the foreseeable future. Our bank credit facility matures in December 2019, and the Company is actively working with its bank group to complete in the near-term the extension of the facility.

The above description of our Bank Credit Agreement is qualified by the express language and defined terms contained in the Bank Credit Agreement and the amendments thereto, each of which are filed as exhibits to our periodic reports filed with the SEC.

Recent Debt Reduction Transactions. Through a series of exchange transactions completed in December 2017 and January 2018 and related conversions of all of our convertible senior notes into equity in April and May 2018, we have reduced our outstanding debt principal of our notes by $328.5 million over the last 7 months. See Overview – Recent Debt Reduction Transactions for further discussion.

Capital Spending. We currently anticipate that our full-year 2018 capital budget, excluding capitalized interest and acquisitions, will be approximately $300 million to $325 million. Capitalized interest is currently estimated at approximately $30 million for 2018. The 2018 capital budget, excluding capitalized interest and acquisitions, provides for approximate spending as follows:

- $155 million allocated for tertiary oil field expenditures;
- $95 million allocated for other areas, primarily non-tertiary oil field expenditures including exploitation;
- $20 million to be spent on CO_2 sources and pipelines; and
- $45 million for other capital items such as capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the six months ended June 30, 2018 and 2017:

	Six Months Ended June 30,	
In thousands	2018	2017
Capital expenditures by project		
Tertiary oil fields	$64,086	$64,768
Non-tertiary fields	32,739	32,772
Capitalized internal costs(1)	22,747	26,717
Oil and natural gas capital expenditures	119,572	124,257
CO_2 pipelines, sources and other	9,648	528
Capital expenditures, before acquisitions and capitalized interest	129,220	124,785
Acquisitions of oil and natural gas properties	21	89,099
Capital expenditures, before capitalized interest	129,241	213,884
Capitalized interest	17,303	12,801
Capital expenditures, total	$146,544	$226,685

(1) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

For the six months ended June 30, 2018, our capital expenditures and property acquisitions were fully funded with $245.6 million of 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, 2017, 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.

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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.
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Operating Results Table

Certain of our operating results and statistics for the comparative three and six months ended June 30, 2018 and 2017 are included in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-share and unit data	2018	2017	2018	2017
Operating results				
Net income	$30,222	$14,399	$69,800	$35,929
Net income per common share – basic	0.07	0.04	0.17	0.09
Net income per common share – diluted	0.07	0.04	0.15	0.09
Net cash provided by operating activities	153,999	52,946	245,626	77,208
Average daily production volumes				
Bbls/d	60,109	57,867	59,236	58,084
Mcf/d	11,314	11,444	11,607	10,616
BOE/d[1]	61,994	59,774	61,171	59,853
Operating revenues				
Oil sales	$373,286	$248,317	$710,692	$512,291
Natural gas sales	2,279	2,563	4,894	4,767
Total oil and natural gas sales	$375,565	$250,880	$715,586	$517,058
Commodity derivative contracts[2]				
Payment on settlements of commodity derivatives	$(54,770)	$(11,767)	$(88,127)	$(38,707)
Noncash fair value gains (losses) on commodity derivatives[3]	(41,429)	22,140	(56,897)	73,682
Commodity derivatives income (expense)	$(96,199)	$10,373	$(145,024)	$34,975
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$68.24	$47.16	$66.29	$48.73
Natural gas price per Mcf	2.21	2.46	2.33	2.48
Unit prices – including impact of derivative settlements[2]				
Oil price per Bbl	$58.23	$44.92	$58.07	$45.05
Natural gas price per Mcf	2.21	2.46	2.33	2.48
Oil and natural gas operating expenses				
Lease operating expenses	$120,384	$111,318	$238,740	$225,158
Marketing expenses, net of third-party purchases, and plant operating expenses	9,508	9,964	19,030	20,052
Production and ad valorem taxes	25,363	18,289	50,395	39,130
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$66.57	$46.12	$64.63	$47.73
Lease operating expenses	21.34	20.46	21.56	20.78
Marketing expenses, net of third-party purchases, and plant operating expenses	1.69	1.83	1.72	1.85
Production and ad valorem taxes	4.50	3.36	4.55	3.61
CO_2 sources – revenues and expenses				
CO_2 sales and transportation fees	$6,715	$6,555	$14,267	$11,943
CO_2 discovery and operating expenses	(500)	(513)	(962)	(1,106)
CO_2 revenue and expenses, net	$6,215	$6,042	$13,305	$10,837

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

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

(3) Noncash fair value gains (losses) 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 gains (losses) on commodity derivatives represent only the net changes between periods of the fair market values of commodity derivative positions, and exclude the impact of settlements on commodity derivatives during the period, which were payments on settlements of $54.8 million and $88.1 million for the three and six months ended June 30, 2018, respectively, compared to payments on settlements of $11.8 million and $38.7 million for the three and six months ended June 30, 2017, respectively. We believe that noncash fair value gains (losses) on commodity derivatives is a useful supplemental disclosure to “Commodity derivatives expense (income)” in order to differentiate noncash fair market value adjustments from receipts or payments upon 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 (loss) to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value gains (losses) 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 2017 and for the first and second quarters of 2018 is shown below:

	Average Daily Production (BOE/d)					
Operating Area	First Quarter 2017	Second Quarter 2017	Third Quarter 2017	Fourth Quarter 2017	First Quarter 2018	Second Quarter 2018
Tertiary oil production						
Gulf Coast region						
Delhi	4,991	4,965	4,619	4,906	4,169	4,391
Hastings	4,288	4,400	4,867	5,747	5,704	5,716
Heidelberg	4,730	4,996	4,927	4,751	4,445	4,330
Oyster Bayou	5,075	5,217	4,870	4,868	5,056	4,961
Tinsley	6,666	6,311	6,506	6,241	6,053	5,755
Other	14	10	19	7	57	142
Mature properties[1]	8,097	7,727	7,431	7,225	7,174	7,160
Total Gulf Coast region	33,861	33,626	33,239	33,745	32,658	32,455
Rocky Mountain region						
Bell Creek	3,209	3,060	3,406	3,571	4,050	4,010
Salt Creek[2]	—	23	2,228	2,172	2,002	2,049
Total Rocky Mountain region	3,209	3,083	5,634	5,743	6,052	6,059
Total tertiary oil production	37,070	36,709	38,873	39,488	38,710	38,514
Non-tertiary oil and gas production						
Gulf Coast region						
Mississippi	1,342	1,004	867	721	875	901
Texas	4,333	5,002	4,024	4,617	4,386	4,947
Other	495	460	515	483	445	400
Total Gulf Coast region	6,170	6,466	5,406	5,821	5,706	6,248
Rocky Mountain region						
Cedar Creek Anticline	15,067	15,124	14,535	14,302	14,437	15,742
Other	1,626	1,475	1,514	1,533	1,485	1,490
Total Rocky Mountain region	16,693	16,599	16,049	15,835	15,922	17,232
Total non-tertiary production	22,863	23,065	21,455	21,656	21,628	23,480
Total production	59,933	59,774	60,328	61,144	60,338	61,994

(1) Mature properties include Brookhaven, Cranfield, Eucutta, Little Creek, Lockhart Crossing, Mallalieu, Martinville, McComb and Soso fields.

(2) Represents production related to the acquisition of a 23% non-operated working interest in Salt Creek Field in Wyoming, which closed on June 30, 2017.

Total production during the second quarter of 2018 averaged 61,994 BOE/d, including 38,514 Bbls/d, or 62%, from tertiary properties and 23,480 BOE/d from non-tertiary properties. This total production level represents an increase of 1,656 BOE/d (3%) compared to first quarter of 2018 production levels, and an increase of 2,220 BOE/d (4%) compared to second quarter of 2017 production levels. Our production during the three and six months ended June 30, 2018 was 97% oil, consistent with oil production during the prior-year period.

Oil production from our tertiary operations during the second quarter of 2018 was essentially unchanged when comparing the first and second quarters of 2018 and increased 1,805 Bbls/d (5%) compared to the same period in 2017. The year-over-year increase in production was due principally to higher production from the redevelopment project in mid-2017 at Hastings Field, production response from continued expansion at Bell Creek Field, and a full quarter of production from the mid-2017 acquisition at Salt Creek Field.

Production from our non-tertiary operations averaged 23,480 BOE/d during the second quarter of 2018, an increase of 1,852 BOE/d (9%) compared to the first quarter of 2018 and an increase of 415 BOE/d (2%) compared to the second quarter of 2017. The sequential quarter increase was primarily due to production increases at Cedar Creek Anticline, which benefited from the strong performance of two new Mission Canyon wells completed during March and April of 2018, and in part to a well recompletion at Webster Field, as well as higher production in the Gulf Coast region in the most recent quarter given weather downtime which impacted production in the first quarter of 2018.

We currently expect third quarter production to be below second quarter levels, mainly due to the second quarter pause in drilling new Mission Canyon wells, unplanned downtime during the third quarter at Cedar Creek Anticline and Oyster Bayou, and the seasonal effect of summer temperatures on a few of our Gulf Coast floods. We expect production to rebound in the fourth quarter, with several new Mission Canyon wells coming online, continued response from our EOR development capital projects, and cooler Gulf Coast temperatures, with our full-year 2018 production still expected to average between 60,000 and 64,000 BOE/d.

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and six months ended June 30, 2018 increased 50% and 38%, respectively, compared to these revenues for the same periods in 2017. The changes in our oil and natural gas revenues are due to changes in production quantities and commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

In thousands	Three Months Ended June 30, 2018 vs. 2017		Six Months Ended June 30, 2018 vs. 2017	
	Increase in Revenues	Percentage Increase in Revenues	Increase in Revenues	Percentage Increase in Revenues
Change in oil and natural gas revenues due to:				
Increase in production	$9,317	4 %	$11,382	2 %
Increase in commodity prices	115,368	46 %	187,146	36 %
Total increase in oil and natural gas revenues	$124,685	50 %	$198,528	38 %

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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, 2018 and 2017:

	Three Months Ended March 31,		Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017
Average net realized prices						
Oil price per Bbl	$64.25	$50.31	$68.24	$47.16	$66.29	$48.73
Natural gas price per Mcf	2.44	2.50	2.21	2.46	2.33	2.48
Price per BOE	62.61	49.35	66.57	46.12	64.63	47.73
Average NYMEX differentials						
Gulf Coast region						
Oil per Bbl	$2.05	$(1.42)	$1.12	$(0.78)	$1.59	$(1.09)
Natural gas per Mcf	0.10	0.09	0.04	(0.03)	0.07	0.03
Rocky Mountain region						
Oil per Bbl	$(0.06)	$(2.09)	$(0.84)	$(1.96)	$(0.39)	$(2.02)
Natural gas per Mcf	(0.92)	(0.97)	(1.25)	(1.42)	(1.08)	(1.19)
Total Company						
Oil per Bbl	$1.29	$(1.64)	$0.39	$(1.16)	$0.87	$(1.39)
Natural gas per Mcf	(0.40)	(0.57)	(0.62)	(0.69)	(0.51)	(0.63)

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, crude oil quality, and location differentials. Our corporate-wide oil differential during the second quarter of 2018 was $0.39 per Bbl above NYMEX prices, compared to an average differential of $1.16 per Bbl below NYMEX in the second quarter of 2017 and $1.29 per Bbl above NYMEX in the first quarter of 2018. Additional information about our oil differentials in the Gulf Coast and Rocky Mountain regions are discussed in further detail below.

Our average NYMEX oil differential in the Gulf Coast region was a positive $1.12 per Bbl and a negative $0.78 per Bbl during the second quarters of 2018 and 2017, respectively, and a positive $2.05 per Bbl during the first quarter of 2018. 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, as well as various other price adjustments such as those noted above. The average LLS-to-NYMEX differential (on a trade-month basis) averaged a positive $3.32 per Bbl in the second quarter of 2018, an increase from the positive $1.95 per Bbl in the second quarter of 2017 and a decrease from the positive $4.12 per Bbl in the first quarter of 2018. During the second quarter of 2018, we sold approximately 60% of our crude oil at prices based on, or 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.

NYMEX oil differentials in the Rocky Mountain region averaged $0.84 per Bbl and $1.96 per Bbl below NYMEX during the second quarters of 2018 and 2017, respectively, and $0.06 per Bbl below NYMEX during the first quarter of 2018. Differentials in the Rocky Mountain region can fluctuate significantly on a month-to-month basis due to weather, refinery or transportation issues, and Canadian and U.S. crude oil price index volatility.

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Commodity Derivative Contracts

The following table summarizes the impact our crude oil derivative contracts had on our operating results for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six months ended June 30,	
In thousands	2018	2017	2018	2017
Payment on settlements of commodity derivatives	$(54,770)	$(11,767)	$(88,127)	$(38,707)
Noncash fair value gains (losses) on commodity derivatives[1]	(41,429)	22,140	(56,897)	73,682
Total income (expense)	$(96,199)	$10,373	$(145,024)	$34,975

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

In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production through 2019 using both NYMEX and LLS fixed-price swaps and three-way collars. See Note 5, Commodity Derivative Contracts, to the Consolidated Financial Statements for additional details of our outstanding commodity derivative contracts as of June 30, 2018, and Item 3, Quantitative and Qualitative Disclosures about Market Risk below for additional discussion. In addition, the following table summarizes our commodity derivative contracts as of August 6, 2018:

		2H 2018	1H 2019	2H 2019
WTI NYMEX	Volumes Hedged (Bbls/d)	15,500	—	—
Fixed-Price Swaps	Swap Price[1]	$50.13	—	—
WTI NYMEX	Volumes Hedged (Bbls/d)	5,000	3,500	—
Fixed-Price Swaps	Swap Price[1]	$56.54	$59.05	—
Argus LLS	Volumes Hedged (Bbls/d)	5,000	—	—
Fixed-Price Swaps	Swap Price[1]	$60.18	—	—
WTI NYMEX	Volumes Hedged (Bbls/d)	15,000	8,500	12,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price[1][2]	$36.50 / $46.50 / $53.88	$47.00 / $55.00 / $66.71	$47.00 / $55.00 / $66.23
WTI NYMEX	Volumes Hedged (Bbls/d)	—	8,000	8,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price[1][2]	—	$50.00 / $58.00 / $73.26	$50.00 / $58.00 / $73.26
WTI NYMEX	Volumes Hedged (Bbls/d)	—	2,000	2,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price[1][2]	—	$52.00 / $60.00 / $70.44	$52.00 / $60.00 / $70.44
Argus LLS	Volumes Hedged (Bbls/d)	—	3,000	3,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price[1][2]	—	$54.00 / $62.00 / $78.50	$54.00 / $62.00 / $78.50
Argus LLS	Volumes Hedged (Bbls/d)	—	1,500	1,500
3-Way Collars	Sold Put Price / Floor / Ceiling Price[1][2]	—	$56.00 / $64.00 / $78.83	$56.00 / $64.00 / $78.83

Total Volumes Hedged (Bbls/d)	40,500	26,500	26,500

(1) Averages are volume weighted.
(2) If oil prices were to average less than the sold put price, receipts on settlement would be limited to the difference between the floor price and the sold put price.

Based on current contracts in place and NYMEX oil futures prices as of August 6, 2018, which averaged approximately $68 per Bbl, we currently expect that we would make cash payments of approximately $110 million during the remainder of 2018 upon settlement of these contracts, the amount of which is dependent upon fluctuations in future NYMEX oil prices in relation to the prices of our fixed-price swaps which have weighted average prices of $51.69 per Bbl and $60.18 per Bbl for NYMEX and LLS hedges, respectively, and weighted average ceiling prices of our three-way collars of $53.88 per Bbl. Changes in commodity prices, expiration of contracts, and new commodity contracts entered into cause fluctuations in the estimated fair value of our oil 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.

Production Expenses

Lease Operating Expenses

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
In thousands, except per-BOE data	2018	2017	2018	2017
Total lease operating expenses	$120,384	$111,318	$238,740	$225,158
Total lease operating expenses per BOE	$21.34	$20.46	$21.56	$20.78

Total lease operating expenses increased $9.1 million (8%) and $13.6 million (6%) on an absolute-dollar basis, or $0.88 (4%) and $0.78 (4%) on a per-BOE basis, during the three and six months ended June 30, 2018, respectively, compared to levels in the same periods in 2017. Our lease operating expenses during the current-year periods were primarily impacted by operating expenses related to our non-operated working interest in Salt Creek Field, which was acquired in June 2017 and has a higher per-BOE operating cost than our corporate average. Lease operating expenses were also impacted by higher CO_2 expense due to increases in oil prices and an increase in power and fuel costs, partially offset by lower workover expense during the current year periods. Sequentially, lease operating expenses slightly increased on an absolute-dollar basis, but decreased $0.46 (2%) on a per-BOE basis between the first quarter of 2018 and the second quarter of 2018 due to higher production volumes.

Currently, our CO_2 expense comprises approximately 20% 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 2018 and 2017, approximately 49% and 58%, respectively, of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned and produced by us (our net revenue interest). 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 was approximately $0.44 per Mcf during the second quarter of 2018, including taxes paid on CO_2 production but excluding depletion, depreciation and amortization of capital expended at our CO_2 source fields and industrial sources. This per-Mcf CO_2 cost during the second quarter of 2018 was higher than the $0.38 per Mcf comparable measure during the second quarter of 2017 and $0.39 per Mcf comparable measure during the first quarter of 2018 due to an increase in the price of CO_2 due to higher oil prices and a higher utilization of industrial-sourced CO_2, which has a higher average cost than our naturally-occurring CO_2 sources.

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. Marketing and plant operating expenses were $11.5 million and $13.9 million for the three months ended June 30, 2018 and 2017, respectively, and $24.0 million and $27.9 million for the six months ended June 30, 2018 and 2017, respectively.

Taxes Other Than Income

Taxes other than income includes production, ad valorem and franchise taxes. Taxes other than income increased $7.1 million (35%) during the three months ended June 30, 2018 compared to the same prior-year period and increased

$11.9 million (28%) during the six months ended June 30, 2018 compared to the same period in 2017 due primarily to an increase in production taxes resulting from higher oil and natural gas revenues.

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General and Administrative Expenses (“G&A”)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
In thousands, except per-BOE data and employees	2018	2017	2018	2017
Gross cash compensation and administrative costs	$57,484	$63,302	$114,522	$129,749
Gross stock-based compensation	3,227	6,044	6,529	11,432
Operator labor and overhead recovery charges	(32,187)	(32,577)	(63,324)	(64,108)
Capitalized exploration and development costs	(9,112)	(10,980)	(18,083)	(23,043)
Net G&A expense	$19,412	$25,789	$39,644	$54,030
G&A per BOE				
Net administrative costs	$2.99	$3.85	$3.11	$4.16
Net stock-based compensation	0.45	0.89	0.47	0.83
Net G&A expenses	$3.44	$4.74	$3.58	$4.99
Employees as of June 30	880	1,073		

Our gross G&A expenses on an absolute-dollar basis decreased $8.6 million (12%) and $20.1 million (14%) during the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017, primarily due to lower employee-related costs such as salaries and long-term incentives during the 2018 period following the August 2017 involuntary workforce reduction.

Net G&A expense on a per-BOE basis decreased 27% and 28% during the three and six months ended June 30, 2018, respectively, compared to levels in the same periods in 2017 due to the items previously mentioned impacting gross G&A during the 2018 periods, partially offset by lower capitalized exploration and development costs.

Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. 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.

Interest and Financing Expenses

In thousands, except per-BOE data and interest rates	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Cash interest[1]	$45,542	$43,352	$92,145	$85,852
Less: interest on Senior Secured Notes and Convertible Senior Notes not reflected as interest for financial reporting purposes[1]	(21,614)	(12,588)	(43,663)	(25,157)
Noncash interest expense	1,131	1,444	2,268	3,345
Less: capitalized interest	(8,851)	(8,147)	(17,303)	(12,801)
Interest expense, net	$16,208	$24,061	$33,447	$51,239
Interest expense, net per BOE	$2.87	$4.42	$3.02	$4.73
Average debt principal outstanding	$2,550,450	$2,869,319	$2,646,049	$2,844,215
Average interest rate[2]	7.1 %	6.0 %	7.0 %	6.0 %

(1) Cash interest is presented on an accrual basis and includes the portion of interest on our 9% Senior Secured Second Lien Notes due 2021 ("2021 Senior Secured Notes"), 2022 Senior Secured Notes, 2023 Convertible Senior Notes and 2024 Convertible Senior Notes versus the GAAP financial statement presentation in which interest on these notes is accounted for as debt and not reflected as interest for financial reporting purposes in accordance with Financial Accounting Standards Board Codification 470-60, Troubled Debt Restructuring by Debtors. See below for further discussion.
(2) Includes commitment fees but excludes debt issue costs.

As reflected in the table above, net interest expense during the three and six months ended June 30, 2018 decreased $7.9 million (33%) and $17.8 million (35%), respectively, when compared to the prior-year periods due primarily to the series of exchange transactions completed during 2017 and 2018 (see Overview – Recent Debt Reduction Transactions). Despite an overall reduction in the debt principal balance as a result of the exchange transactions, our average interest rate increased between the second quarter of 2017 and 2018 as the combined interest payments on the senior secured and convertible senior notes was higher than the previously issued senior subordinated notes. As more fully described in Note 4, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements, the exchange transactions were accounted for in accordance with Financial Accounting Standards Board Codification 470-60, Troubled Debt Restructuring by Debtors, whereby most of the future interest associated with the 2021 Senior Secured Notes, 2022 Senior Secured Notes, 2023 Convertible Senior Notes and 2024 Convertible Senior Notes was recorded as debt as of the transaction date, which will be reduced as semiannual interest payments are made. During the second quarter of 2018, the debt principal balance and future interest applicable to the 2024 Convertible Senior Notes and 2023 Convertible Senior Notes, respectively, were reclassified to "Paid-in capital in excess of par" and "Common stock" in our Unaudited Condensed Consolidated Balance Sheets upon the conversion of those notes into shares of Denbury common stock (see Overview – Recent Debt Reduction Transactions). The conversion of these notes saves the Company annual cash interest payments of $5.9 million. Future interest payable related to our senior secured second lien notes recorded as debt totaled $292.6 million as of June 30, 2018. Therefore, interest expense reflected in our Unaudited Condensed Consolidated Financial Statements will be significantly lower than the actual cash interest payment. Capitalized interest during the six months ended June 30, 2018 increased $4.5 million (35%) compared to the same period in 2017, primarily due to an increase in the number of projects that qualify for interest capitalization.

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Depletion, Depreciation, and Amortization (“DD&A”)

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data	2018	2017	2018	2017
Oil and natural gas properties	$33,358	$29,165	$65,229	$56,983
CO_2 properties, pipelines, plants and other property and equipment	19,586	21,987	40,166	45,364
Total DD&A	$52,944	$51,152	$105,395	$102,347
DD&A per BOE				
Oil and natural gas properties	$5.91	$5.36	$5.89	$5.26
CO_2 properties, pipelines, plants and other property and equipment	3.47	4.04	3.63	4.19
Total DD&A cost per BOE	$9.38	$9.40	$9.52	$9.45

The increase in our oil and natural gas properties depletion during the three and six months ended June 30, 2018 when compared to the same periods in 2017 was primarily due to an increase in depletable costs associated with our reserves base, partially offset by an increase in proved oil and natural gas reserve quantities. Total DD&A per BOE was also impacted by increases in production volumes during 2018 when compared to production in the 2017 periods.

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE amounts and tax rates	2018	2017	2018	2017
Current income tax benefit	$(754)	$(5,965)	$(1,786)	$(19,900)
Deferred income tax expense	10,185	16,238	25,237	51,147
Total income tax expense	$9,431	$10,273	$23,451	$31,247
Average income tax expense per BOE	$1.68	$1.89	$2.12	$2.88
Effective tax rate	23.8 %	41.6 %	25.1 %	46.5 %
Total net deferred tax liability	$231,761	$345,025		

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. Our income taxes are based on an estimated statutory rate of approximately 25% and 38% in 2018 and 2017, respectively, due to a reduction of the federal income tax rate from 35% to 21% as enacted by the Tax Cut and Jobs Act in December 2017. Our effective tax rate for the three months ended June 30, 2017 was higher than our estimated statutory rate, primarily due to the impact of alternative minimum tax credit usage during that quarter, and our effective tax rate for the six months ended June 30, 2017 differed from our estimated statutory rate primarily due to the impact of a tax shortfall on a stock-based compensation deduction (tax deduction less than book expense recognized) of $3.8 million.

The current income tax benefits for the three and six months ended June 30, 2018 and 2017, represent the estimated receivable resulting from alternative minimum tax credits.

As of June 30, 2018, we had an estimated $51.5 million of enhanced oil recovery credits to carry forward related to our tertiary operations, $21.6 million of research and development credits, and $10.1 million of alternative minimum tax credits (net of $10.2 million related to the estimated credits to be applied to our 2018 tax return), which under the

Tax Cut and Jobs Act, will be fully refundable by 2021. The enhanced oil recovery credits and research and development credits do not begin to expire until 2024 and 2031, respectively.

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	2018	2017	2018	2017
Oil and natural gas revenues	$66.57	$46.12	$64.63	$47.73
Payment on settlements of commodity derivatives	(9.71)	(2.16)	(7.96)	(3.57)
Lease operating expenses	(21.34)	(20.46)	(21.56)	(20.78)
Production and ad valorem taxes	(4.50)	(3.36)	(4.55)	(3.61)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.69)	(1.83)	(1.72)	(1.85)
Production netback	29.33	18.31	28.84	17.92
CO_2 sales, net of operating and exploration expenses	1.10	1.12	1.20	1.00
General and administrative expenses	(3.44)	(4.74)	(3.58)	(4.99)
Interest expense, net	(2.87)	(4.42)	(3.02)	(4.73)
Other	(0.33)	1.72	0.01	2.53
Changes in assets and liabilities relating to operations	3.51	(2.26)	(1.27)	(4.60)
Cash flows from operations	27.30	9.73	22.18	7.13
DD&A	(9.38)	(9.40)	(9.52)	(9.45)
Deferred income taxes	(1.81)	(2.99)	(2.28)	(4.72)
Noncash fair value gains (losses) on commodity derivatives[1]	(7.34)	4.07	(5.14)	6.80
Other noncash items	(3.41)	1.24	1.06	3.56
Net income	$5.36	$2.65	$6.30	$3.32

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

CRITICAL ACCOUNTING POLICIES

For additional discussion of our critical accounting policies, see Management's Discussion and Analysis of Financial Condition and Results of Operations in our Form 10-K. Any new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements have been included in the notes to the Company's Unaudited Condensed Consolidated Financial Statements contained in this Quarterly Report on Form 10-Q.

FORWARD-LOOKING INFORMATION

The data and/or 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, financial forecasts, future hydrocarbon prices and volatility, the sustainability of current oil prices, the degree and length of any price recovery for oil, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to further reduce our debt levels, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows, availability of capital, borrowing capacity, availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, the nature of any future asset sales or the timing or proceeds thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, including CCA, or the availability of capital for CCA pipeline construction, or its ultimate cost or date of completion, timing of CO_2 injections and initial production responses in tertiary flooding projects, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, potential increases in worldwide tariffs or other trade restrictions, the likelihood, timing and impact of increased interest rates, the impact of regulatory rulings or changes, anticipated outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, long-term forecasts of production, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions and other variables surrounding our estimated original oil in place, operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," "may" or other words that convey, or 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 our 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 us or on our behalf. 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 our oil and natural gas; decisions as to production levels and/or pricing by OPEC or production levels by U.S. shale producers in future periods; levels of future capital expenditures; effects of our indebtedness; success of our risk management techniques; accuracy of our cost estimates; availability or terms of credit in the commercial banking or other debt markets; fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, forest fires, or other natural occurrences; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including changes in tax or environmental laws or regulations; 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 our other public reports, filings and public statements including, without limitation, the Company's most recent Form 10-K.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Debt and Interest Rate Sensitivity

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. As of June 30, 2018, we had $415.0 million of debt outstanding on our senior secured 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 light of credit downgrades in February 2016, we were required to provide a $41.3 million letter of credit to the lessor, which we provided on March 4, 2016. The letter of credit may be drawn upon in the event we fail to make a payment due under the pipeline financing lease agreement or upon other specified defaults set out in the pipeline financing lease agreement (filed as Exhibit 99.1 to the Form 8-K filed with the SEC on June 5, 2008). The fair values of our senior secured second lien notes and senior subordinated notes are based on quoted market prices. The following table presents the principal and fair values of our outstanding debt as of June 30, 2018.

In thousands	2019	2021	2022	2023	Total	Fair Value
Variable rate debt:						
Senior Secured Bank Credit Facility (weighted average interest rate of 4.7% at June 30, 2018)	$415,000	$ —	$ —	$ —	$415,000	$415,000
Fixed rate debt:						
9% Senior Secured Second Lien Notes due 2021	—	614,919	—	—	614,919	650,092
9¼% Senior Secured Second Lien Notes due 2022	—	—	455,668	—	455,668	481,003
6 % Senior Subordinated Notes due 2021	—	203,545	—	—	203,545	192,350
5½% Senior Subordinated Notes due 2022	—	—	314,662	—	314,662	291,062
4 % Senior Subordinated Notes due 2023	—	—	—	307,978	307,978	269,573

See Note 4, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements for details regarding our long-term debt.

Commodity Derivative Contracts

We enter into oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. 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. In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production through 2019 using both NYMEX and LLS fixed-price swaps and three-way collars. Depending on market conditions, we may continue to add to our existing 2019 hedges. See also Note 5, Commodity Derivative Contracts, and Note 6, Fair Value Measurements, 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 commodity 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 senior secured bank credit facility (or affiliates of such lenders). We have included an estimate of nonperformance risk in the fair value measurement of our commodity 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 commodity derivative contracts. This means that any changes in the fair value of these commodity derivative contracts will be charged to earnings instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

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At June 30, 2018, our commodity derivative contracts were recorded at their fair value, which was a net liability of $156.0 million, a $41.5 million increase from the $114.5 million net liability recorded at March 31, 2018, and a $56.9 million increase from the $99.1 million net liability recorded at December 31, 2017. These changes are primarily related to the expiration of commodity derivative contracts during the three and six months ended June 30, 2018, new commodity derivative contracts entered into during 2018 for future periods, and to the changes in oil futures prices between December 31, 2017 and June 30, 2018.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of June 30, 2018, and assuming both a 10% increase and decrease thereon, we would expect to make payments on our crude oil derivative contracts as shown in the following table:

In thousands	Receipt / (Payment) Crude Oil Derivative Contracts
Based on:	
Futures prices as of June 30, 2018	$(140,111)
10% increase in prices	(218,417)
10% decrease in prices	(80,045)

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 production to which those commodity derivative contracts relate.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of 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, 2018, 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, that it is 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 2018, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC. The helium supply contract provides for the delivery of a minimum contracted quantity of helium, subject to adjustment after startup of the Riley Ridge gas processing facility, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are specified in the contract at up to $8.0 million per contract year and are capped at an aggregate of $46.0 million over the term of the contract. As the gas processing facility has been shut-in since mid-2014, we have not been able to supply helium under the helium supply contract. APMTG Helium, LLC filed a case in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, claiming multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company’s position is that our contractual obligations are excused by virtue of events that fall within the force majeure provisions in the helium supply contract. The evidentiary phase of the trial concluded on November 29, 2017. The parties submitted written closing briefs and rebuttal briefs to the District Court during February and April of 2018. We currently expect a ruling from the District Court to be made during 2018. The Company plans to continue to vigorously defend its position, but we are unable to predict at this time the outcome of this dispute.

Environmental Protection Agency Matter Concerning Citronelle and Other Fields

The Company has entered into a series of tolling agreements (effective through October 31, 2018) with the Environmental Protection Agency (“EPA”), and has been in discussions with the agency over the past several years regarding the EPA’s contention that it has causes of action under the Clean Water Act (“CWA”) related to releases (principally between 2008 and 2013) of oil and produced water containing small amounts of oil in the Citronelle Field in southern Alabama and several fields in Mississippi. The EPA has taken the position that these releases were in violation of the CWA. Discussions are focused upon actions taken or to be taken by Denbury, including enhancements to the Company’s mechanical integrity program designed to minimize the occurrence and impact of any future releases in these fields.

Based upon recent discussions with the EPA, the Company currently anticipates that in the next several months it will reach agreement with the EPA as to a consent decree regarding the EPA’s claims, which consent decree will likely provide for a monetary fine as a civil penalty. The Company anticipates that any civil penalty to which it would agree would not be material to the Company’s business or financial condition.

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.

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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 2018:

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 2018	1,101	$ 3.04	—	$ 210.1
May 2018	9,494	3.80	—	210.1
June 2018	7,856	3.97	—	210.1
Total	18,451		—	

(1) Shares purchased during the second quarter of 2018 were made in connection with the surrender of shares by our employees to satisfy their tax withholding requirements related to the vesting of restricted and performance shares.

(2) In October 2011, we commenced a common share repurchase program, which has been approved for up to an aggregate of $1.162 billion of Denbury common shares by the Company’s Board of Directors. This program has effectively been suspended and we do not anticipate repurchasing shares of our common stock in the near future. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

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Item 6. Exhibits

Exhibit No.	Exhibit
10(a)*	Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(b)*	Form of Restricted Share Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files.

* Included herewith.

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 8, 2018	/s/ Mark C. Allen Mark C. Allen Executive Vice President and Chief Financial Officer
August 8, 2018	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer