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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2021
OR

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

For the transition period from _______ to ________

Commission file number: **001-12935**

DENBURY 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.)*
5851 Legacy Circle,	
Plano, TX	**75024**
(Address of principal executive offices)	*(Zip Code)*
Registrant's telephone number, including area code:	**(972) 673-2000**

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class:	**Trading Symbol:**	**Name of Each Exchange on Which Registered:**
Common Stock $.001 Par Value	DEN	New York Stock Exchange

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☐	Accelerated filer ☑	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☑	Emerging growth company ☐

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. ☐

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

The number of shares outstanding of the registrant's Common Stock, $.001 par value, as of July 31, 2021, was 50,109,950.

Denbury Inc.

Table of Contents

		Page
	PART I. FINANCIAL INFORMATION	
Item 1.	Financial Statements	
	Unaudited Condensed Consolidated Balance Sheets	3
	Unaudited Condensed Consolidated Statements of Operations	4
	Unaudited Condensed Consolidated Statements of Cash Flows	5
	Unaudited Condensed Consolidated Statements of Changes in Stockholders’ Equity	6
	Notes to Unaudited Condensed Consolidated Financial Statements	7
Item 2.	Management’s Discussion and Analysis of Financial Condition and Results of Operations	17
Item 3.	Quantitative and Qualitative Disclosures about Market Risk	33
Item 4.	Controls and Procedures	35
	PART II. OTHER INFORMATION	
Item 1.	Legal Proceedings	36
Item 1A.	Risk Factors	36
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	37
Item 3.	Defaults Upon Senior Securities	37
Item 4.	Mine Safety Disclosures	37
Item 5.	Other Information	37
Item 6.	Exhibits	38
	Signatures	39

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Successor	
	June 30, 2021	December 31, 2020
Assets		
Current assets		
Cash and cash equivalents	$ 13,565	$ 518
Restricted cash	—	1,000
Accrued production receivable	140,302	91,421
Trade and other receivables, net	24,740	19,682
Derivative assets	—	187
Prepaids	12,454	14,038
Total current assets	191,061	126,846
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	949,128	851,208
Unevaluated properties	103,088	85,304
CO_2 properties	188,700	188,288
Pipelines	143,633	133,485
Other property and equipment	97,699	86,610
Less accumulated depletion, depreciation, amortization and impairment	(120,073)	(41,095)
Net property and equipment	1,362,175	1,303,800
Operating lease right-of-use assets	19,000	20,342
Intangible assets, net	92,814	97,362
Other assets	85,044	86,408
Total assets	$ 1,750,094	$ 1,634,758
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 163,905	$ 112,671
Oil and gas production payable	69,390	49,165
Derivative liabilities	223,212	53,865
Current maturities of long-term debt	34,498	68,008
Operating lease liabilities	2,596	1,350
Total current liabilities	493,601	285,059
Long-term liabilities		
Long-term debt, net of current portion	35,000	70,000
Asset retirement obligations	226,615	179,338
Derivative liabilities	22,164	5,087
Deferred tax liabilities, net	1,187	1,274
Operating lease liabilities	18,157	19,460
Other liabilities	26,172	20,872
Total long-term liabilities	329,295	296,031
Commitments and contingencies (Note 8)		
Stockholders' equity		
Preferred stock, $.001 par value, 50,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $.001 par value, 250,000,000 shares authorized; 50,017,491 and 49,999,999 shares issued, respectively	50	50
Paid-in capital in excess of par	1,125,143	1,104,276
Accumulated deficit	(197,995)	(50,658)
Total stockholders' equity	927,198	1,053,668
Total liabilities and stockholders' equity	$ 1,750,094	$ 1,634,758

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Revenues and other income				
Oil, natural gas, and related product sales	$ 282,708	$ 109,387	$ 518,153	$ 339,011
CO_2 sales and transportation fees	10,134	6,504	19,362	14,532
Oil marketing revenues	7,819	1,490	13,945	5,211
Other income	707	494	1,067	1,322
Total revenues and other income	301,368	117,875	552,527	360,076
Expenses				
Lease operating expenses	110,225	81,293	192,195	190,563
Transportation and marketing expenses	8,522	9,388	16,319	19,009
CO_2 operating and discovery expenses	1,531	885	2,524	1,637
Taxes other than income	22,382	10,372	41,345	30,058
Oil marketing expenses	7,738	1,450	13,823	5,111
General and administrative expenses	15,450	23,776	47,433	33,509
Interest, net of amounts capitalized of $1,168, $8,729, $2,251 and $18,181, respectively	1,252	20,617	2,788	40,563
Depletion, depreciation, and amortization	36,381	55,414	75,831	152,276
Commodity derivatives expense (income)	172,664	40,130	288,407	(106,641)
Gain on debt extinguishment	—	—	—	(18,994)
Write-down of oil and natural gas properties	—	662,440	14,377	734,981
Other expenses	3,214	11,290	5,360	13,784
Total expenses	379,359	917,055	700,402	1,095,856
Loss before income taxes	(77,991)	(799,180)	(147,875)	(735,780)
Income tax benefit	(296)	(101,706)	(538)	(112,322)
Net loss	$ (77,695)	$ (697,474)	$ (147,337)	$ (623,458)
Net loss per common share				
Basic	$ (1.52)	$ (1.41)	$ (2.91)	$ (1.26)
Diluted	$ (1.52)	$ (1.41)	$ (2.91)	$ (1.26)
Weighted average common shares outstanding				
Basic	50,999	495,245	50,661	494,752
Diluted	50,999	495,245	50,661	494,752

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Successor	Predecessor
	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Cash flows from operating activities		
Net loss	$ (147,337)	$ (623,458)
Adjustments to reconcile net loss to cash flows from operating activities		
Depletion, depreciation, and amortization	75,831	152,276
Write-down of oil and natural gas properties	14,377	734,981
Deferred income taxes	(87)	(106,513)
Stock-based compensation	20,232	3,540
Commodity derivatives expense (income)	288,407	(106,641)
Receipt (payment) on settlements of commodity derivatives	(101,796)	70,267
Gain on debt extinguishment	—	(18,994)
Debt issuance costs and discounts	1,370	9,921
Other, net	744	(1,642)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	(48,881)	62,063
Trade and other receivables	(5,578)	(16,162)
Other current and long-term assets	1,294	(4,552)
Accounts payable and accrued liabilities	27,292	(60,295)
Oil and natural gas production payable	20,224	(22,217)
Other liabilities	(2,554)	237
Net cash provided by operating activities	143,538	72,811
Cash flows from investing activities		
Oil and natural gas capital expenditures	(53,411)	(79,897)
Acquisitions of oil and natural gas properties	(10,811)	—
Pipelines and plants capital expenditures	(4,851)	(10,962)
Net proceeds from sales of oil and natural gas properties and equipment	18,456	40,971
Other	(4,159)	(105)
Net cash used in investing activities	(54,776)	(49,993)
Cash flows from financing activities		
Bank repayments	(485,000)	(226,000)
Bank borrowings	450,000	491,000
Interest payments treated as a reduction of debt	—	(42,506)
Cash paid in conjunction with debt repurchases	—	(14,171)
Pipeline financing and capital lease debt repayments	(33,510)	(7,015)
Other	(2,735)	(9,529)
Net cash provided by (used in) financing activities	(71,245)	191,779
Net increase in cash, cash equivalents, and restricted cash	17,517	214,597
Cash, cash equivalents, and restricted cash at beginning of period	42,248	33,045
Cash, cash equivalents, and restricted cash at end of period	$ 59,765	$ 247,642

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Inc.
Unaudited Condensed Consolidated Statements 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)		
	Shares	Amount			Shares	Amount	Total Equity
Balance – December 31, 2020 (Successor)	49,999,999	$ 50	$ 1,104,276	$ (50,658)	—	$ —	$ 1,053,668
Stock-based compensation	—	—	19,172	—	—	—	19,172
Tax withholding for stock compensation plans	—	—	(1,467)	—	—	—	(1,467)
Issued pursuant to exercise of warrants	5,620	0	195	—	—	—	195
Net loss	—	—	—	(69,642)	—	—	(69,642)
Balance – March 31, 2021 (Successor)	50,005,619	50	1,122,176	(120,300)	—	—	1,001,926
Stock-based compensation	—	—	2,682	—	—	—	2,682
Tax withholding for stock compensation plans	—	—	(7)	—	—	—	(7)
Issued pursuant to exercise of warrants	11,872	0	292	—	—	—	292
Net loss	—	—	—	(77,695)	—	—	(77,695)
Balance – June 30, 2021 (Successor)	50,017,491	$ 50	$ 1,125,143	$ (197,995)	—	$ —	$ 927,198

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Treasury Stock (at cost)		
	Shares	Amount			Shares	Amount	Total Equity
Balance – December 31, 2019 (Predecessor)	508,065,495	$ 508	$ 2,739,099	$ (1,321,314)	1,652,771	$ (6,034)	$ 1,412,259
Issued pursuant to stock compensation plans	312,516	—	—	—	—	—	—
Issued pursuant to directors' compensation plan	37,367	—	—	—	—	—	—
Stock-based compensation	—	—	3,204	—	—	—	3,204
Tax withholding for stock compensation plans	—	—	—	—	175,673	(34)	(34)
Net income	—	—	—	74,016	—	—	74,016
Balance – March 31, 2020 (Predecessor)	508,415,378	508	2,742,303	(1,247,298)	1,828,444	(6,068)	1,489,445
Canceled pursuant to stock compensation plans	(6,218,868)	(6)	6	—	—	—	—
Issued pursuant to notes conversion	7,357,450	8	11,453	—	—	—	11,461
Stock-based compensation	—	—	987	—	—	—	987
Net loss	—	—	—	(697,474)	—	—	(697,474)
Balance – June 30, 2020 (Predecessor)	509,553,960	510	2,754,749	(1,944,772)	1,828,444	(6,068)	804,419
Canceled pursuant to stock compensation plans	(95,016)	—	—	—	—	—	—
Issued pursuant to notes conversion	14,800	—	40	—	—	—	40
Stock-based compensation	—	—	10,126	—	—	—	10,126
Tax withholding for stock compensation plans	—	—	—	—	567,189	(134)	(134)
Net loss	—	—	—	(809,120)	—	—	(809,120)
Cancellation of Predecessor equity	(509,473,744)	(510)	(2,764,915)	2,753,892	(2,395,633)	6,202	(5,331)
Issuance of Successor equity	49,999,999	50	1,095,369	—	—	—	1,095,419
Balance – September 18, 2020 (Predecessor)	49,999,999	$ 50	$ 1,095,369	$ —	—	$ —	$ 1,095,419
Balance – September 19, 2020 (Successor)	49,999,999	$ 50	$ 1,095,369	$ —	—	$ —	$ 1,095,419
Net income	—	—	—	2,758	—	—	2,758
Balance – September 30, 2020 (Successor)	49,999,999	50	1,095,369	2,758	—	—	1,098,177
Stock-based compensation	—	—	8,907	—	—	—	8,907
Net loss	—	—	—	(53,416)	—	—	(53,416)
Balance – December 31, 2020 (Successor)	49,999,999	$ 50	$ 1,104,276	$ (50,658)	—	$ —	$ 1,053,668

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

Denbury Inc. ("Denbury," "Company" or the "Successor"), a Delaware corporation, is an independent energy company with operations focused in the Gulf Coast and Rocky Mountain regions. The Company is differentiated by its focus on CO_2 enhanced oil recovery ("EOR") and the emerging carbon capture, use, and storage ("CCUS") industry, supported by the Company's CO_2 EOR technical and operational expertise and its extensive CO_2 pipeline infrastructure. The utilization of captured industrial-sourced CO_2 in EOR significantly reduces the carbon footprint of the oil that Denbury produces, underpinning the Company's goal to fully offset its Scope 1, 2, and 3 CO_2 emissions within this decade, primarily through increasing the amount of captured industrial-sourced CO_2 used in its operations.

Emergence from Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On July 30, 2020, Denbury Resources Inc. (the "Predecessor") and its subsidiaries filed petitions for reorganization in a "prepackaged" voluntary bankruptcy under chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court") under the caption "*In re Denbury Resources Inc., et al.*, Case No. 20-33801". On September 2, 2020, the Bankruptcy Court entered an order (the "Confirmation Order") confirming the prepackaged joint plan of reorganization (the "Plan") and approving the Disclosure Statement, and on September 18, 2020 (the "Emergence Date"), the Plan became effective in accordance with its terms and the Company emerged from Chapter 11 as the successor reporting company of Denbury Resources Inc. On April 23, 2021, the Bankruptcy Court entered a final decree closing the Chapter 11 case captioned "*In re Denbury Resources Inc., et al.*, Case No. 20-33801", so all of the Chapter 11 cases have been closed.

Upon emergence from bankruptcy, we met the criteria and were required to adopt fresh start accounting in accordance with Financial Accounting Standards Board Codification ("FASC") Topic 852, *Reorganizations*. Fresh start accounting requires that new fair values be established for the Company's assets, liabilities and equity as of the Emergence Date, and therefore certain values and operational results of the condensed consolidated financial statements subsequent to September 18, 2020 are not comparable to those in the Company's condensed consolidated financial statements prior to, and including September 18, 2020. The Emergence Date fair values of the Successor's assets and liabilities differ materially from their recorded values as reflected on the historical balance sheets of the Predecessor contained in periodic reports previously filed with the Securities and Exchange Commission. References to "Successor" relate to the financial position and results of operations of the Company subsequent to September 18, 2020, and references to "Predecessor" relate to the financial position and results of operations of the Company prior to, and including, September 18, 2020.

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury 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, 2020 (the "Form 10-K"). Unless indicated otherwise or the context requires, the terms "we," "our," "us," "Company" or "Denbury," refer to Denbury 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 presentation of our consolidated financial position as of June 30, 2021 (Successor); our consolidated results of operations for the three and six months ended June 30, 2021 (Successor) and June 30, 2020 (Predecessor); our consolidated cash flows for the six months ended June 30, 2021 (Successor) and June 30, 2020 (Predecessor); and our consolidated statements of changes in stockholders' equity for the three and six months ended June 30, 2021 (Successor), for the period January 1, 2020 through September 18, 2020 (Predecessor), and for the period September 19, 2020 through December 31, 2020 (Successor). Upon the adoption of fresh start accounting, the Company's assets and liabilities were recorded at their fair values as of the fresh start reporting date. As a result of the adoption of fresh start

accounting, certain values and operational results of the Company's condensed consolidated financial statements subsequent to September 18, 2020 are not comparable to those in its condensed consolidated financial statements prior to, and including September 18, 2020.

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 (loss), 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:

	Successor	
In thousands	June 30, 2021	December 31, 2020
Cash and cash equivalents	$ 13,565	$ 518
Restricted cash, current	—	1,000
Restricted cash included in other assets	46,200	40,730
Total cash, cash equivalents, and restricted cash shown in the Unaudited Condensed Consolidated Statements of Cash Flows	$ 59,765	$ 42,248

Restricted cash included in other assets in the table above consists of escrow accounts that are legally restricted for certain of our asset retirement obligations, and are included in "Other assets" in the accompanying Unaudited Condensed Consolidated Balance Sheets.

Net Income (Loss) per Common Share

Basic net income (loss) per common share is computed by dividing the net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner but includes the impact of potentially dilutive securities. Potentially dilutive securities during the Successor periods consist of nonvested restricted stock units and outstanding series A and series B warrants, and during the Predecessor periods consisted of nonvested restricted stock, nonvested performance-based equity awards, and convertible senior notes. For the three and six months ended June 30, 2021 and 2020, there were no adjustments to net loss for purposes of calculating basic and diluted net loss per common share.

Denbury Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

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

	Successor	Predecessor	Successor	Predecessor
In thousands	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Weighted average common shares outstanding – basic	50,999	495,245	50,661	494,752
Effect of potentially dilutive securities				
Restricted stock units	—	—	—	
Warrants	—	—	—	—
Restricted stock and performance-based equity awards	—	—	—	—
Convertible senior notes(1)	—	—	—	—
Weighted average common shares outstanding – diluted(2)	50,999	495,245	50,661	494,752

(1) In connection with the Company's emergence from bankruptcy on September 18, 2020, all outstanding convertible senior notes were fully extinguished.

(2) If the Company had recognized net income, the weighted average diluted shares outstanding would have been 54.3 million and 587.1 million for the three months ended June 30, 2021 and 2020, respectively, and 52.7 million and 586.6 million for the six months ended June 30, 2021 and 2020, respectively.

Basic weighted average common shares during the Successor periods includes 987,987 and 563,416 performance stock units during the three and six months ended June 30, 2021, respectively, with vesting parameters tied to the Company's common stock trading prices and which became fully vested on March 3, 2021. Although the performance measures for vesting of these awards have been achieved, the shares underlying these awards are not currently outstanding as actual delivery of the shares is not scheduled to occur until after the end of the performance period, December 4, 2023. Basic weighted average common shares during the Predecessor periods included time-vesting restricted stock that vested during the periods.

The following outstanding securities were excluded from the computation of diluted net loss per share, as their effect would have been antidilutive, as of the respective dates:

	Successor	Predecessor
In thousands	June 30, 2021	June 30, 2020
Restricted stock units	1,255	—
Warrants	5,503	—
Stock appreciation rights	—	1,493
Nonvested time-based restricted stock and performance-based equity awards	—	5,572
Convertible senior notes	—	83,495

For the Successor period, the Company's restricted stock units and series A and series B warrants were antidilutive based on the Company's net loss position for the period. At June 30, 2021, the Company had approximately 5.5 million warrants outstanding that can be exercised for shares of the Successor's common stock, at an exercise price of $32.59 per share for the 2.6 million series A warrants and at an exercise price of $35.41 per share for the 2.9 million series B warrants. The series A warrants are exercisable until September 18, 2025, and the series B warrants are exercisable until September 18, 2023, at which time the warrants expire. The warrants were issued pursuant to the Plan to holders of the Predecessor's convertible senior notes, senior subordinated notes, and equity. As of June 30, 2021, 2,315 series A warrants and 20,927 series B warrants had been exercised. The warrants may be exercised for cash or on a cashless basis. If warrants are exercised on a cashless basis, the amount of dilution will be less than 5.5 million shares.

Oil and Natural Gas Properties

Unevaluated Costs. Under full cost accounting, we exclude certain unevaluated costs from the amortization base and full cost ceiling test pending the determination of whether proved reserves can be assigned to such properties. These costs are transferred to the full cost amortization base as these properties are developed, tested and evaluated. At least annually, we test these assets for impairment based on an evaluation of management's expectations of future pricing, evaluation of lease expiration terms, and planned development activities. In the first quarter of 2020 Predecessor period, given the significant declines in NYMEX oil prices in March and April 2020, we reassessed our development plans and transferred $244.9 million of our unevaluated costs to the full cost amortization base. Upon emergence from bankruptcy, the Company adopted fresh start accounting which resulted in our oil and natural gas properties, including unevaluated properties, being recorded at their fair values at the Emergence Date.

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

We recognized a full cost pool ceiling test write-down of $14.4 million during the three months ended March 31, 2021, with first-day-of-the-month NYMEX oil prices for the preceding 12 months averaging $36.40 per Bbl, after adjustments for market differentials and transportation expenses by field. The write-down was primarily a result of the recent acquisition (see *Note 2 – Acquisition and Divestiture*) which was recorded based on a valuation that utilized NYMEX strip oil prices at the acquisition date, which were significantly higher than the average first-day-of-the-month NYMEX oil prices used to value the cost ceiling. We also recognized full cost pool ceiling test write-downs of $662.4 million and $72.5 million during the Predecessor three months ended June 30, 2020 and March 31, 2020, respectively. We did not record a ceiling test write-down during the three months ended June 30, 2021.

Recent Accounting Pronouncements

Recently Adopted

Income Taxes. In December 2019, the Financial Accounting Standards Board ("FASB") issued ASU 2019-12, *Income Taxes (Topic 740) – Simplifying the Accounting for Income Taxes* ("ASU 2019-12"). The objective of ASU 2019-12 is to simplify the accounting for income taxes by removing certain exceptions to the general principles in Topic 740 and to provide more consistent application to improve the comparability of financial statements. Effective January 1, 2021, we adopted ASU 2019-02. The implementation of this standard did not have a material impact on our consolidated financial statements and related footnote disclosures.

Note 2. Acquisition and Divestiture

Acquisition of Wyoming CO_2 EOR Fields

On March 3, 2021, we acquired a nearly 100% working interest (approximately 83% net revenue interest) in the Big Sand Draw and Beaver Creek EOR fields located in Wyoming from a subsidiary of Devon Energy Corporation for $10.7 million cash (before final closing adjustments), including surface facilities and a 46-mile CO_2 transportation pipeline to the acquired fields. The acquisition agreement provides for us to make two contingent cash payments, one in January 2022 and one in January 2023, of $4 million each, conditioned on NYMEX WTI oil prices averaging at least $50 per Bbl during 2021 and 2022, respectively. The fair value of the contingent consideration on the acquisition date was $5.3 million, and as of June 30, 2021, the fair value of the contingent consideration recorded on our unaudited condensed consolidated balance sheets was $7.0 million. The $1.7 million increase from the March 2021 acquisition date fair value was the result of higher NYMEX WTI oil prices and was recorded to “Other expenses” in our Unaudited Condensed Consolidated Statements of Operations.

The fair values allocated to our assets acquired and liabilities assumed for the acquisition were based on significant inputs not observable in the market and considered level 3 inputs. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the acquisition:

In thousands		
Consideration:		
Cash consideration	$	10,657
Less: Fair value of assets acquired and liabilities assumed:[(1)]		
Proved oil and natural gas properties		59,852
Other property and equipment		1,685
Asset retirement obligations		(39,794)
Contingent consideration		(5,320)
Other liabilities		(5,766)
Fair value of net assets acquired	$	10,657

(1) Fair value of assets acquired and liabilities assumed is preliminary, pending final closing adjustments and further evaluation of reserves and liabilities assumed.

Divestiture of Hartzog Draw Deep Mineral Rights

On June 30, 2021, we closed the sale of undeveloped, unconventional deep mineral rights in Hartzog Draw Field in Wyoming. The cash proceeds of $18 million were recorded to “Proved properties” in our Unaudited Condensed Consolidated Balance Sheets. The proceeds reduced our full cost pool; therefore, no gain or loss was recorded on the transaction, and the sale had no impact on our production or reserves.

Note 3. Revenue Recognition

We record revenue in accordance with FASC Topic 606, *Revenue from Contracts with Customers*. The core principle of FASC 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. 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 received within a month following product delivery and for natural gas and NGL contracts payment is generally received 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. From time to time,

the Company enters into marketing arrangements for the purchase and sale of crude oil for third parties. Revenues and expenses from these transactions are presented on a gross basis, as we act as a principal in the transaction by assuming control of the commodities purchased and responsibility to deliver the commodities sold. Revenue is recognized when control transfers to the purchaser at the delivery point based on the price received from the purchaser.

Disaggregation of Revenue

The following table summarizes our revenues by product type:

	Successor	Predecessor	Successor	Predecessor
In thousands	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Oil sales	$ 280,577	$ 108,538	$ 513,621	$ 337,115
Natural gas sales	2,131	849	4,532	1,896
CO_2 sales and transportation fees	10,134	6,504	19,362	14,532
Oil marketing revenues	7,819	1,490	13,945	5,211
Total revenues	$ 300,661	$ 117,381	$ 551,460	$ 358,754

Note 4. Long-Term Debt

The table below reflects long-term debt outstanding as of the dates indicated:

	Successor	
In thousands	June 30, 2021	December 31, 2020
Senior Secured Bank Credit Agreement	$ 35,000	$ 70,000
Pipeline financings	34,498	68,008
Total debt principal balance	69,498	138,008
Less: current maturities of long-term debt	(34,498)	(68,008)
Long-term debt	$ 35,000	$ 70,000

Senior Secured Bank Credit Agreement

On the Emergence Date, we entered into a credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the “Bank Credit Agreement”). The Bank Credit Agreement is a senior secured revolving credit facility with an initial borrowing base and lender commitments of $575 million. Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined semiannually on or around May 1 and November 1 of each year, with our next scheduled redetermination around November 1, 2021. The borrowing base is adjusted at the lenders’ discretion and is based, in part, upon external factors over which we have no control. If our outstanding debt under the Bank Credit Agreement exceeds the then-effective borrowing base, we would be required to repay the excess amount over a period not to exceed six months. The Bank Credit Agreement matures on January 30, 2024. The weighted average interest rate on borrowings outstanding as of June 30, 2021 under the Bank Credit Agreement was 4.0%. The undrawn portion of the aggregate lender commitments under the Bank Credit Agreement is subject to a commitment fee of 0.5% per annum.

The Bank Credit Agreement prohibits us from paying dividends on our common stock through September 17, 2021. Commencing on September 18, 2021, we may pay dividends on our common stock or make other restricted payments in an amount not to exceed “Distributable Free Cash Flow”, but only if (1) no event of default or borrowing base deficiency exists; (2) our total leverage ratio is 2 to 1 or lower; and (3) availability under the Bank Credit Agreement is at least 20%. The Bank Credit Agreement also limits our ability to, among other things, incur and repay other indebtedness; grant liens; engage in certain mergers, consolidations, liquidations and dissolutions; engage in sales of assets; make acquisitions and investments; make other restricted payments (including redeeming, repurchasing or retiring our common stock); and enter into commodity derivative agreements, in each case subject to customary exceptions.

The Successor Bank Credit Agreement is secured by (1) our proved oil and natural gas properties, which are held through our restricted subsidiaries; (2) the pledge of equity interests of such subsidiaries; (3) a pledge of our commodity derivative agreements; (4) a pledge of deposit accounts, securities accounts and our commodity accounts; and (5) a security interest in substantially all other collateral that may be perfected by a Uniform Commercial Code filing, subject to certain exceptions.

The Bank Credit Agreement contains certain financial performance covenants including the following:

- A Consolidated Total Debt to Consolidated EBITDAX covenant (as defined in the Bank Credit Agreement), with such ratio not to exceed 3.5 times; and
- A requirement to maintain a current ratio (i.e., Consolidated Current Assets to Consolidated Current Liabilities) of 1.0 time.

For purposes of computing the current ratio per the Bank Credit Agreement, Consolidated Current Assets exclude the current portion of derivative assets but include available borrowing capacity under the Bank Credit Agreement, and Consolidated Current Liabilities exclude the current portion of derivative liabilities as well as the current portions of long-term indebtedness outstanding. As of June 30, 2021, we were in compliance with all debt covenants under the Bank Credit Agreement.

The above description of our Bank Credit Agreement is qualified by the express language and defined terms contained in the Bank Credit Agreement.

Pipeline Financing Transactions

During the first half of 2021, Denbury paid $35.0 million to Genesis Energy, L.P., half of the four quarterly installments totaling $70 million to be paid during 2021 in accordance with the October 2020 restructuring of the financing arrangements of our NEJD CO_2 pipeline system. The third quarterly installment of $17.5 million was paid in July 2021, and the final quarterly payment of $17.5 million is payable on October 31, 2021.

Note 5. Income Taxes

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to our ordinary income or loss to calculate our estimated tax liability or benefit. Our income taxes are based on an estimated combined federal and state statutory rate of approximately 25% in 2021 and 2020. Our effective tax rates for the three and six months ended June 30, 2021 (Successor) differed from our estimated statutory rate as the deferred tax benefit generated from our operating losses were offset by a valuation allowance applied to our underlying federal and state deferred tax assets.

Note 6. 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. In addition, our new senior secured bank credit facility entered into on the Emergence Date required that, by December 31, 2020, we have certain minimum commodity hedge levels in place covering anticipated crude oil production through July 31, 2022. The requirement is non-recurring, and we were in compliance with the hedging requirements as of December 31, 2020.

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, 2021, 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.

The following table summarizes our commodity derivative contracts as of June 30, 2021, none of which are classified as hedging instruments in accordance with the FASC *Derivatives and Hedging* topic:

			Contract Prices ($/Bbl)			
				Weighted Average Price		
Months	Index Price	Volume (Barrels per day)	Range(1)	Swap	Floor	Ceiling
Oil Contracts:						
2021 Fixed-Price Swaps						
July – Dec	NYMEX	29,000	$ 38.68 – 56.00	$ 43.86	$ —	$ —
2021 Collars						
July – Dec	NYMEX	4,000	$ 45.00 – 59.30	$ —	$ 46.25	$ 53.04
2022 Fixed-Price Swaps						
Jan – June	NYMEX	15,500	$ 42.65 – 58.15	$ 49.01	$ —	$ —
July – Dec	NYMEX	9,000	50.13 – 60.35	56.35	—	—
2022 Collars						
Jan – June	NYMEX	11,000	$ 47.50 – 70.75	$ —	$ 49.77	$ 64.31
July – Dec	NYMEX	10,000	47.50 – 70.75	—	49.75	64.18

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

Note 7. 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 and 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.

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, 2021				
Liabilities				
Oil derivative contracts – current	$ —	$ (223,212)	$ —	$ (223,212)
Oil derivative contracts – long-term	—	(22,164)	—	(22,164)
Total Liabilities	$ —	$ (245,376)	$ —	$ (245,376)
December 31, 2020				
Assets				
Oil derivative contracts – current	$ —	$ 187	$ —	$ 187
Total Assets	$ —	$ 187	$ —	$ 187
Liabilities				
Oil derivative contracts – current	$ —	$ (53,865)	$ —	$ (53,865)
Oil derivative contracts – long-term	—	(5,087)	—	(5,087)
Total Liabilities	$ —	$ (58,952)	$ —	$ (58,952)

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.

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. The estimated fair value of the principal amount of our debt as of June 30, 2021 and December 31, 2020, excluding pipeline financing obligations, was $35.0 million and $70.0 million. We have other financial instruments consisting primarily of cash, cash equivalents, U.S. Treasury notes, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 8. Commitments and Contingencies

Chapter 11 Proceedings

On July 30, 2020, Denbury Resources Inc. and each of its wholly-owned subsidiaries filed for relief under chapter 11 of the Bankruptcy Code. The chapter 11 cases were administered jointly under the caption "*In re Denbury Resources Inc., et al.*, Case No. 20-33801". On September 2, 2020, the Bankruptcy Court entered the Confirmation Order and on the Emergence Date, all of the conditions of the Plan were satisfied or waived and the Plan became effective and was implemented in accordance with its terms. On September 30, 2020, the Bankruptcy Court closed the chapter 11 cases of each of Denbury Inc.'s wholly-owned subsidiaries. On April 23, 2021, the Bankruptcy Court entered a final decree closing the Chapter 11 case captioned "*In re Denbury Resources Inc., et al.*, Case No. 20-33801", so all of the Chapter 11 cases have been closed.

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. We accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Note 9. Additional Balance Sheet Details

Trade and Other Receivables, Net

	Successor	
In thousands	June 30, 2021	December 31, 2020
Trade accounts receivable, net	$ 11,795	$ 11,691
Federal income tax receivable, net	597	597
Commodity derivative settlement receivables	—	5,716
Other receivables[1]	12,348	1,678
Total	$ 24,740	$ 19,682

(1) Primarily consists of a currently estimated $9.9 million benefit under the Company's power agreements for reduced power usage during the winter storms in February 2021.

Accounts Payable and Accrued Liabilities

	Successor	
In thousands	June 30, 2021	December 31, 2020
Accounts payable	$ 27,166	$ 18,629
Accrued derivative settlements	26,121	3,908
Accrued lease operating expenses	24,802	21,294
Accrued compensation	21,428	7,512
Accrued exploration and development costs	12,361	1,861
Taxes payable	10,180	17,221
Accrued general and administrative expenses	4,432	21,825
Other	37,415	20,421
Total	$ 163,905	$ 112,671

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, 2020 (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.

As a result of the Company's emergence from bankruptcy and adoption of fresh start accounting on September 18, 2020 (the "Emergence Date"), certain values and operational results of the condensed consolidated financial statements subsequent to September 18, 2020 are not comparable to those in the Company's condensed consolidated financial statements prior to, and including September 18, 2020. The Emergence Date fair values of the Successor's assets and liabilities differ materially from their recorded values as reflected on the historical balance sheets of the Predecessor contained in periodic reports previously filed with the Securities and Exchange Commission. References to "Successor" relate to the financial position and results of operations of the Company subsequent to September 18, 2020, and references to "Predecessor" relate to the financial position and results of operations of the Company prior to, and including, September 18, 2020.

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 this Form 10-Q as well as 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 energy company with operations focused in the Gulf Coast and Rocky Mountain regions. The Company is differentiated by its focus on CO_2 enhanced oil recovery ("EOR") and the emerging carbon capture, use, and storage ("CCUS") industry, supported by the Company's CO_2 EOR technical and operational expertise and its extensive CO_2 pipeline infrastructure. The utilization of captured industrial-sourced CO_2 in EOR significantly reduces the carbon footprint of the oil that Denbury produces, underpinning the Company's goal to fully offset its Scope 1, 2, and 3 CO_2 emissions within this decade, primarily through increasing the amount of captured industrial-sourced CO_2 used in its operations.

Oil Price Impact on Our Business. Our financial results are significantly impacted by changes in oil prices, as 97% of our sales is oil. Changes in oil prices impact all aspects of our business; most notably our cash flows from operations, revenues, capital allocation and budgeting decisions, and oil and natural gas reserves volumes. The table below outlines selected financial

items and sales volumes, along with changes in our realized oil prices, before and after commodity derivative impacts, for our most recent comparative periods:

	Successor			Predecessor
	Three Months Ended			Three Months Ended
In thousands, except per-unit data	June 30, 2021	March 31, 2021	December 31, 2020	June 30, 2020
Oil, natural gas, and related product sales	$ 282,708	$ 235,445	$ 178,787	$ 109,387
Receipt (payment) on settlements of commodity derivatives	(63,343)	(38,453)	14,429	45,629
Oil, natural gas, and related product sales and commodity settlements, combined	$ 219,365	$ 196,992	$ 193,216	$ 155,016
Average daily sales (BOE/d)	49,133	47,357	48,805	50,190
Average net realized prices				
Oil price per Bbl - excluding impact of derivative settlements	$ 64.70	$ 56.28	$ 40.63	$ 24.39
Oil price per Bbl - including impact of derivative settlements	50.10	47.00	43.94	34.64

NYMEX WTI oil prices strengthened from the mid-$40s per Bbl range in December 2020 to an average of approximately $66 per Bbl during the second quarter of 2021, reaching highs of over $74 per Bbl in June 2021.

Second Quarter 2021 Financial Results and Highlights. We recognized a net loss of $77.7 million, or $1.52 per diluted common share, during the second quarter of 2021, compared to a net loss of $697.5 million, or $1.41 per diluted common share, during the second quarter of 2020. The principal determinant of our comparative second quarter results between 2020 and 2021 was the $662.4 million full cost pool ceiling test write-down in the prior-year period. Additional drivers of the comparative operating results include the following:

- Oil and natural gas revenues increased $173.3 million (158%), primarily due to an increase in commodity prices;
- Commodity derivatives expense increased by $132.5 million consisting of a $109.0 million decrease in cash receipts upon contract settlements ($63.3 million in payments during the second quarter of 2021 compared to $45.6 million in receipts upon settlements during the second quarter of 2020) and a $23.5 million increase in the loss on noncash fair value changes;
- A $28.9 million increase in lease operating expense, across nearly all expense categories, consisting of increases of $8.4 million in workovers, $4.4 million in CO_2 expense, $3.7 million in power and fuel, and approximately $7.1 million due to the Wind River Basin acquisition in March 2021;
- A $19.4 million reduction in net interest expense resulting from the full extinguishment of senior secured second lien notes, convertible senior notes, and senior subordinated notes pursuant to the terms of the prepackaged joint plan of reorganization completed in September 2020;
- A reduction in depletion, depreciation, and amortization expense of $19.0 million as a result of lower depletable costs due to the step down in book value resulting from fresh start accounting on the Emergence Date; and
- An $8.3 million decrease in general and administrative expense in the second quarter of 2021, primarily due to higher expense in the prior-year period as a result of modifications in our compensation program during the second quarter of 2020 which resulted in adjustments to the bonus program for 2020, as well as certain severance-related costs recorded during the second quarter of 2020.

June 2021 Divestiture of Hartzog Draw Deep Mineral Rights. On June 30, 2021, we closed the sale of undeveloped, unconventional deep mineral rights in Hartzog Draw Field in Wyoming. The cash proceeds of $18 million were recorded to "Proved properties" in our Unaudited Condensed Consolidated Balance Sheets. The proceeds reduced our full cost pool; therefore, no gain or loss was recorded on the transaction, and the sale had no impact on our production or reserves.

March 2021 Acquisition of Wyoming CO_2 EOR Fields. On March 3, 2021, we acquired a nearly 100% working interest (approximately 83% net revenue interest) in the Big Sand Draw and Beaver Creek EOR fields (collectively "Wind River Basin") located in Wyoming from a subsidiary of Devon Energy Corporation for $10.7 million cash (before final closing adjustments), including surface facilities and a 46-mile CO_2 transportation pipeline to the acquired fields. The acquisition agreement provides for us to make two contingent cash payments, one in January 2022 and one in January 2023, of $4 million each, conditioned on NYMEX WTI oil prices averaging at least $50 per Bbl during 2021 and 2022, respectively. As of June 30, 2021, the contingent consideration was recorded on our unaudited condensed consolidated balance sheets at its fair value of $7.0 million, a $1.7 million increase from the March 2021 acquisition date fair value. This $1.7 million increase was the result of higher NYMEX WTI oil prices and was recorded to "Other expenses" in our Unaudited Condensed Consolidated Statements of Operations. Wind River Basin sales averaged approximately 2,750 BOE/d during the second quarter of 2021 and utilize 100% industrial-sourced CO_2.

Carbon Capture, Use and Storage. CCUS is a process that captures CO_2 from industrial sources and reuses it or stores the CO_2 in geologic formations in order to prevent its release into the atmosphere. We utilize CO_2 from industrial sources in our EOR operations, and our extensive CO_2 pipeline infrastructure and operations, particularly in the Gulf Coast, are strategically located in close proximity to large sources of industrial emissions. We believe that the assets and technical expertise required for CCUS are highly aligned with our existing CO_2 EOR operations, providing us with a significant advantage and opportunity to participate in the emerging CCUS industry, as the building of a permanent carbon sequestration business requires both time and capital to build assets such as those we own and have been operating for years. During the first half of 2021, approximately 34% of the CO_2 utilized in our oil and gas operations was industrial-sourced CO_2, and we anticipate this percentage could increase in the future as supportive U.S. government policy and public pressure on industrial CO_2 emitters will provide strong incentives for these entities to capture their CO_2 emissions. In an effort to proactively pursue these new CCUS opportunities, we are engaged in discussions with existing and potential third-party industrial CO_2 emitters regarding transportation and storage solutions, while also identifying potential future sequestration sites and landowners of those locations. While EOR is the only CCUS operation reflected in our current and historical financial and operational results, and development of our permanent carbon sequestration business is likely to take several years, we believe Denbury is well positioned to leverage our existing CO_2 pipeline infrastructure and EOR expertise to be a leader in this industry.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and availability under our senior secured bank credit facility. Our most significant cash capital outlays in 2021 relate to our $250 million to $270 million of budgeted development capital expenditures and $70 million of pipeline financing obligations associated with the NEJD pipeline. Based on our current 2021 full-year projections using recent oil price futures, we currently expect that our cash flow from operations in 2021 will more than cover our budgeted development capital expenditures and also cover a significant portion of our pipeline financing obligations. In addition, we have sold certain non-producing assets that will further supplement our cash flow from operations.

As of June 30, 2021, we had $35 million of outstanding borrowings on our $575 million senior secured bank credit facility, leaving us with $517.7 million of borrowing base availability after consideration of $22.3 million of outstanding letters of credit. Our borrowing base availability, coupled with unrestricted cash of $13.6 million, provides us total liquidity of $531.3 million as of June 30, 2021, which is more than adequate to meet our currently planned operating and capital needs.

2021 Plans and Capital Budget. Considering the current oil price environment and strategic importance of the EOR CO_2 flood at Cedar Creek Anticline ("CCA"), we announced in February 2021 our plans to move forward with development of this significant long-term project. We expect to spend approximately $150 million in 2021 on this CCA development, consisting of approximately $100 million dedicated to the 105-mile extension of the Greencore CO_2 pipeline from Bell Creek to CCA, with the remainder dedicated to facilities, well work and field development at CCA. Based on our current plans, most of the capital spend for the pipeline extension to CCA will occur in the second half of 2021, with completion of the pipeline expected by the end of 2021, first CO_2 injection planned during the first half of 2022, and first tertiary production expected in the second half of 2023. We currently anticipate that our full-year 2021 development capital spending, excluding capitalized interest and

acquisitions, will be in a range of $250 million to $270 million. Our current 2021 capital budget, excluding capitalized interest and acquisitions, at the $260 million midpoint level is as follows:

- $100 million for the 105-mile extension of the Greencore CO_2 pipeline to CCA;
- $50 million for CCA tertiary well work, facilities, and field development;
- $50 million allocated for other tertiary oil field development;
- $35 million allocated for non-tertiary oil field development; and
- $25 million for other capital items such as capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

We currently anticipate 2021 average daily sales volumes to be between 47,500 BOE/d and 51,500 BOE/d, including the Big Sand Draw and Beaver Creek working interests acquisition which closed in early March 2021.

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the six months ended June 30, 2021 and 2020:

In thousands	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Capital expenditure summary		
CCA tertiary development	$ 10,260	$ 2,151
Other tertiary oil fields	20,774	17,769
Non-tertiary fields	19,523	13,248
Capitalized internal costs[(1)]	14,785	18,344
Oil and natural gas capital expenditures	65,342	51,512
CCA CO_2 pipeline	8,839	8,374
Other CO_2 pipelines, sources and other	—	158
Development capital expenditures	74,181	60,044
Acquisitions of oil and natural gas properties[(2)]	10,811	80
Capital expenditures, before capitalized interest	84,992	60,124
Capitalized interest	2,251	18,181
Capital expenditures, total	$ 87,243	$ 78,305

(1) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.
(2) Primarily consists of working interest positions in the Wind River Basin enhanced oil recovery fields acquired on March 3, 2021.

Based on current oil prices and the Company's hedge positions, we expect that our 2021 cash flows from operations will exceed our budgeted level of planned development capital expenditures.

Senior Secured Bank Credit Agreement. In September 2020, we entered into a bank credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). The Bank Credit Agreement is a senior secured revolving credit facility with a maturity date of January 30, 2024. As part of our spring 2021 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $575 million, with our next scheduled redetermination around November 2021. The borrowing base is adjusted at the lenders' discretion and is based, in part, upon external factors over which we have no control. If our outstanding debt under the Bank Credit Agreement exceeds the then-effective borrowing base, we would be required to repay the excess amount over a

period not to exceed six months. The Bank Credit Agreement contains certain financial performance covenants including the following:

- A Consolidated Total Debt to Consolidated EBITDAX covenant (as defined in the Bank Credit Agreement), with such ratio not to exceed 3.5 times; and
- A requirement to maintain a current ratio (i.e., Consolidated Current Assets to Consolidated Current Liabilities) of 1.0 time.

For purposes of computing the current ratio per the Bank Credit Agreement, Consolidated Current Assets exclude the current portion of derivative assets but include available borrowing capacity under the Bank Credit Agreement, and Consolidated Current Liabilities exclude the current portion of derivative liabilities as well as the current portions of long-term indebtedness outstanding. Under these financial performance covenant calculations, as of June 30, 2021, our ratio of consolidated total debt to consolidated EBITDAX was 0.18 to 1.0 (with a maximum permitted ratio of 3.5 to 1.0) and our current ratio was 3.00 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 4, 2021, and current oil commodity derivative futures prices, we currently anticipate continuing to be in compliance with our financial performance covenants during the foreseeable future.

The above description of our Bank Credit Agreement is qualified by the express language and defined terms contained in the Bank Credit Agreement, which is an exhibit to our Form 8-K Report filed with the SEC on September 18, 2020.

Commitments and Obligations. We have numerous contractual commitments in the ordinary course of business including debt service requirements, operating and finance leases, purchase obligations, and asset retirement obligations. Our operating leases primarily consist of our office leases. Our purchase obligations represent future cash commitments primarily for purchase contracts for CO_2 captured from industrial sources, CO_2 processing fees, transportation agreements and well-related costs.

Our commitments and obligations consist of those detailed as of December 31, 2020, in our Form 10-K under *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments, Obligations and Off-Balance Sheet Arrangements*. During the six months ended June 30, 2021, our long-term asset retirement obligations increased by $47.3 million, primarily related to our acquisition of working interest positions in Wyoming CO_2 EOR fields (see Note 2, *Acquisition and Divestiture*).

Off-Balance Sheet Arrangements. Our off-balance sheet arrangements include obligations for various 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.

RESULTS OF OPERATIONS

Certain of our financial and operating results and statistics for the comparative three and six months ended June 30, 2021 and 2020 are included in the following table:

In thousands, except per-share and unit data	Successor Three Months Ended June 30, 2021	Predecessor Three Months Ended June 30, 2020	Successor Six Months Ended June 30, 2021	Predecessor Six Months Ended June 30, 2020
Financial results				
Net loss[1]	$ (77,695)	$ (697,474)	$ (147,337)	$ (623,458)
Net loss per common share – basic[1]	(1.52)	(1.41)	(2.91)	(1.26)
Net loss per common share – diluted[1]	(1.52)	(1.41)	(2.91)	(1.26)
Net cash provided by operating activities	90,882	10,969	143,538	72,811
Average daily sales volumes				
Bbls/d	47,653	48,900	46,834	51,774
Mcf/d	8,882	7,737	8,494	7,818
BOE/d[2]	49,133	50,190	48,250	53,077
Oil and natural gas sales				
Oil sales	$ 280,577	$ 108,538	$ 513,621	$ 337,115
Natural gas sales	2,131	849	4,532	1,896
Total oil and natural gas sales	$ 282,708	$ 109,387	$ 518,153	$ 339,011
Commodity derivative contracts[3]				
Receipt (payment) on settlements of commodity derivatives	$ (63,343)	$ 45,629	$ (101,796)	$ 70,267
Noncash fair value gains (losses) on commodity derivatives	(109,321)	(85,759)	(186,611)	36,374
Commodity derivatives income (expense)	$ (172,664)	$ (40,130)	$ (288,407)	$ 106,641
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$ 64.70	$ 24.39	$ 60.59	$ 35.78
Natural gas price per Mcf	2.64	1.21	2.95	1.33
Unit prices – including impact of derivative settlements[3]				
Oil price per Bbl	$ 50.10	$ 34.64	$ 48.58	$ 43.23
Natural gas price per Mcf	2.64	1.21	2.95	1.33
Oil and natural gas operating expenses				
Lease operating expenses	$ 110,225	$ 81,293	$ 192,195	$ 190,563
Transportation and marketing expenses	8,522	9,388	16,319	19,009
Production and ad valorem taxes	21,836	8,766	39,731	26,753
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$ 63.23	$ 23.95	$ 59.33	$ 35.09
Lease operating expenses	24.65	17.80	22.01	19.73
Transportation and marketing expenses	1.91	2.06	1.87	1.97
Production and ad valorem taxes	4.88	1.92	4.55	2.77
CO_2 – revenues and expenses				
CO_2 sales and transportation fees	$ 10,134	$ 6,504	$ 19,362	$ 14,532
CO_2 operating and discovery expenses	(1,531)	(885)	(2,524)	(1,637)
CO_2 revenue and expenses, net	$ 8,603	$ 5,619	$ 16,838	$ 12,895

(1) Includes a pre-tax full cost pool ceiling test write-down of $14.4 million during the first quarter of 2021, as compared to write-downs of $662.4 million and $735.0 million for the three and six months ended June 30, 2020, respectively.
(2) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas ("BOE").
(3) See also *Commodity Derivative Contracts* below and *Item 3. Quantitative and Qualitative Disclosures about Market Risk* for information concerning our derivative transactions.

Sales Volumes

Average daily sales volumes by area for each of the four quarters of 2020 and for the first and second quarters of 2021 is shown below:

	Average Daily Sales Volumes (BOE/d)					
Operating Area	First Quarter 2021	Second Quarter 2021	First Quarter 2020	Second Quarter 2020	Third Quarter 2020	Fourth Quarter 2020
Tertiary oil sales						
Gulf Coast region						
Delhi	2,925	2,931	3,813	3,529	3,208	3,132
Hastings	4,226	4,487	5,232	4,722	4,473	4,598
Heidelberg	4,054	3,942	4,371	4,366	4,256	4,198
Oyster Bayou	3,554	3,791	3,999	3,871	3,526	3,880
Tinsley	3,424	3,455	4,355	3,788	4,042	3,654
Other[(1)]	6,098	6,074	7,161	5,944	6,271	6,332
Total Gulf Coast region	24,281	24,680	28,931	26,220	25,776	25,794
Rocky Mountain region						
Bell Creek	4,614	4,394	5,731	5,715	5,551	5,079
Other[(2)]	2,573	4,378	2,199	1,393	2,167	2,007
Total Rocky Mountain region	7,187	8,772	7,930	7,108	7,718	7,086
Total tertiary oil sales	31,468	33,452	36,861	33,328	33,494	32,880
Non-tertiary oil and gas sales						
Gulf Coast region						
Total Gulf Coast region	3,621	3,415	4,173	3,805	3,728	3,523
Rocky Mountain region						
Cedar Creek Anticline	11,150	10,918	13,046	11,988	11,485	11,433
Other[(2)]	1,118	1,348	1,105	1,069	979	969
Total Rocky Mountain region	12,268	12,266	14,151	13,057	12,464	12,402
Total non-tertiary sales	15,889	15,681	18,324	16,862	16,192	15,925
Total continuing sales	47,357	49,133	55,185	50,190	49,686	48,805
Property sales						
Gulf Coast Working Interests Sale[(3)]	—	—	780	—	—	—
Total sales	47,357	49,133	55,965	50,190	49,686	48,805

(1) Includes our mature properties (Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb and Soso fields) and West Yellow Creek Field.
(2) Includes sales volumes related to our working interest positions in the Big Sand Draw and Beaver Creek fields acquired on March 3, 2021.
(3) Includes non-tertiary sales related to the March 2020 sale of 50% of our working interests in Webster, Thompson, Manvel, and East Hastings fields (the "Gulf Coast Working Interests Sale").

Total sales volumes during the second quarter of 2021 averaged 49,133 BOE/d, including 33,452 Bbls/d from tertiary properties and 15,681 BOE/d from non-tertiary properties. This sales volume represents an increase of 1,776 BOE/d (4%) compared to sales levels in the first quarter of 2021 and a decrease of 1,057 BOE/d (2%) compared to second quarter of 2020. The increase on a sequential-quarter basis was primarily attributable to our Wind River Basin acquisition in March 2021 and sales from these properties during the most recent quarter.

The year-over-year decline was primarily impacted by (1) the carryover impact of exceptionally low levels of capital investment in 2020, significantly below levels required to hold production flat, (2) decreases at CCA due to the net profits interest of a third party, whereby increased oil prices have resulted in increased profitability and thus, lower reported sales volumes net to Denbury of approximately 625 BOE/d when compared to the second quarter of 2020, and (3) declines at Delhi Field due to lower CO_2 purchases between late-February and late-October 2020 as a result of the Delta-Tinsley pipeline being down for repair. The year-over-year decline in sales volumes was partially offset by sales increases from our Wind River Basin enhanced oil recovery fields acquired on March 3, 2021.

Our sales volumes during the three and six months ended June 30, 2021 were 97% oil, consistent with our 97% and 98% oil sales during the same prior-year periods.

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and six months ended June 30, 2021 increased 158% and 53%, respectively, compared to these revenues for the same periods in 2020. The changes in our oil and natural gas revenues are due primarily to higher realized commodity prices (excluding any impact of our commodity derivative contracts), offset somewhat by changes in sales volumes, as reflected in the following table:

	Three Months Ended June 30, 2021 vs. 2020		Six Months Ended June 30, 2021 vs. 2020	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Decrease in sales volumes	$ (2,303)	(2)%	$ (32,528)	(10)%
Increase in realized commodity prices	175,624	160 %	211,670	63 %
Total increase in oil and natural gas revenues	$ 173,321	158 %	$ 179,142	53 %

Excluding any impact of our commodity derivative contracts, our average net realized commodity prices and NYMEX differentials were as follows during the three months ended March 31, 2021 and 2020 and the three and six months ended June 30, 2021 and 2020:

	Three Months Ended March 31,		Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020	2021	2020
Average net realized prices						
Oil price per Bbl	$ 56.28	$ 45.96	$ 64.70	$ 24.39	$ 60.59	$ 35.78
Natural gas price per Mcf	3.29	1.46	2.64	1.21	2.95	1.33
Price per BOE	55.24	45.09	63.23	23.95	59.33	35.09
Average NYMEX differentials						
Gulf Coast region						
Oil per Bbl	$ (1.37)	$ 1.18	$ (1.13)	$ (3.59)	$ (1.23)	$ (0.53)
Natural gas per Mcf	0.68	(0.06)	(0.11)	(0.09)	0.30	(0.07)
Rocky Mountain region						
Oil per Bbl	$ (1.80)	$ (2.78)	$ (1.59)	$ (4.68)	$ (1.54)	$ (3.25)
Natural gas per Mcf	0.49	(0.91)	(0.47)	(1.04)	(0.04)	(0.98)
Total Company						
Oil per Bbl	$ (1.54)	$ (0.38)	$ (1.32)	$ (4.03)	$ (1.36)	$ (1.61)
Natural gas per Mcf	0.58	(0.41)	(0.33)	(0.54)	0.11	(0.48)

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.

- **Gulf Coast Region**. Our average NYMEX oil differential in the Gulf Coast region was a negative $1.13 per Bbl during the second quarter of 2021, compared to a negative $3.59 per Bbl during the second quarter of 2020 and a negative $1.37 per Bbl during the first quarter of 2021. For both the first quarter of 2020 and for many years prior, our Gulf Coast region differentials were positive to NYMEX due to historically higher prices received for Gulf Coast crudes, such as Light Louisiana Sweet crude oil. As a result of the market disruptions, storage constraints and weak demand caused by the COVID-19 coronavirus ("COVID-19") pandemic, these differentials weakened significantly during the second quarter of 2020 and have remained lower than historical values since April 2020.

- **Rocky Mountain Region**. NYMEX oil differentials in the Rocky Mountain region averaged $1.59 per Bbl and $4.68 per Bbl below NYMEX during the second quarters of 2021 and 2020, respectively, and $1.80 per Bbl below NYMEX during the first quarter of 2021. Differentials in the Rocky Mountain region tend to fluctuate with regional supply and demand trends and 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.

CO_2 Revenues and Expenses

We sell CO_2 produced from Jackson Dome to third-party industrial users at various contracted prices primarily under long-term contracts. We recognize the revenue received on these CO_2 sales as "CO_2 sales and transportation fees" with the corresponding costs recognized as "CO_2 operating and discovery expenses" in our Unaudited Condensed Consolidated Statements of Operations.

Oil Marketing Revenues and Expenses

From time to time, we market third-party production for sale in exchange for a fee. We recognize the revenue received on these oil sales as "Oil marketing sales" and the expenses incurred to market and transport the oil as "Oil marketing expenses" in our Unaudited Condensed Consolidated Statements of Operations.

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, 2021 and 2020:

	Successor	Predecessor	Successor	Predecessor
In thousands	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Receipt (payment) on settlements of commodity derivatives	$ (63,343)	$ 45,629	$ (101,796)	$ 70,267
Noncash fair value gains (losses) on commodity derivatives	(109,321)	(85,759)	(186,611)	36,374
Total income (expense)	$ (172,664)	$ (40,130)	$ (288,407)	$ 106,641

Changes in our commodity derivatives expense were primarily related to the expiration of commodity derivative contracts, new commodity derivative contracts entered into for future periods, and to the changes in oil futures prices between the second quarters of 2020 and 2021. The period-to-period changes reflect the very large fluctuations in oil prices between March 2020 ($30.45 per barrel), when worldwide financial markets were first beginning to absorb the potential impact of a global pandemic, and June 2021 oil prices ($71.35 per barrel) as prospects for increased economic activity and oil demand showed improvement.

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 2022 using NYMEX fixed-price swaps and costless collars. See Note 6, *Commodity Derivative Contracts*, to the Unaudited Condensed Consolidated Financial Statements for additional details of our outstanding commodity

derivative contracts as of June 30, 2021, 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 4, 2021:

		2H 2021	1H 2022	2H 2022
WTI NYMEX	Volumes Hedged (Bbls/d)	29,000	15,500	9,000
Fixed-Price Swaps	Swap Price(1)	$43.86	$49.01	$56.35
WTI NYMEX	Volumes Hedged (Bbls/d)	4,000	11,000	10,000
Collars	Floor / Ceiling Price(1)	$46.25 / $53.04	$49.77 / $64.31	$49.75 / $64.18
	Total Volumes Hedged (Bbls/d)	33,000	26,500	19,000

(1) Averages are volume weighted.

Based on current contracts in place and NYMEX oil futures prices as of August 4, 2021, which averaged approximately $68 per Bbl, we currently expect that we would make cash payments of approximately $145 million upon settlement of our July through December 2021 contracts, the amount of which is primarily dependent upon fluctuations in future NYMEX oil prices in relation to the prices of our 2021 fixed-price swaps which have a weighted average NYMEX oil price of $43.69 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

	Successor	Predecessor	Successor	Predecessor
In thousands, except per-BOE data	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Total lease operating expenses	$ 110,225	$ 81,293	$ 192,195	$ 190,563
Total lease operating expenses per BOE	$ 24.65	$ 17.80	$ 22.01	$ 19.73

Total lease operating expenses increased $28.9 million (36%) and $1.6 million (1%) on an absolute-dollar basis, or $6.85 (38%) and $2.28 (12%) on a per-BOE basis, during the three and six months ended June 30, 2021, respectively, compared to the same prior-year periods. The increase during the second quarter of 2021 on an absolute-dollar basis compared to the same period in 2020 was primarily due to (a) higher expenses across nearly all expense categories as our costs are correlated to varying degrees with changes in oil prices, with the largest increases attributable to workovers ($8.4 million), CO_2 expense ($4.4 million), and power and fuel ($3.7 million) and (b) 2020 period reduced spending and shut-in production in response to significantly lower oil prices in the second quarter of 2020. Lease operating expenses during the three months ended June 30, 2021 were further impacted by $7.1 million of expense related to the Wind River Basin acquisition in March 2021, as these properties have higher operating costs than our other fields. Lease operating expenses for the six months ended June 30, 2021 were relatively flat with the same prior-year period as increased expenses resulting from our Wind River Basin acquisition in March 2021 and increases in workover and CO_2 expense were largely offset by a $11.1 million reduction in power and fuel costs. The significant reduction in power and fuel costs was associated with the severe winter storm in February 2021 which created widespread power outages in Texas and disrupted the Company's operations. Under certain of the Company's power agreements the Company is compensated for its reduced power usage, which resulted in a benefit to the Company of approximately $16.3 million; as of June 30, 2021, $9.9 million of these savings were included in "Trade and other receivables, net" and $3.7 million included in "Other assets" in our Unaudited Condensed Consolidated Balance Sheets. Compared to the first quarter of 2021, lease operating expenses in the most recent quarter increased $28.3 million (34%) on an absolute-dollar basis and $5.42 (28%) on a per-BOE basis, due primarily to the first quarter 2021 utility benefit mentioned above, the second quarter of 2021 reflecting a full quarter of operating expenses for the Wind River Basin properties acquired in March 2021, as well as increases in workover and CO_2 expense.

Transportation and Marketing Expenses

Transportation and marketing expenses primarily consist of amounts incurred relating to the transportation, marketing, and processing of oil and natural gas production. Transportation and marketing expenses were $8.5 million and $9.4 million for the three months ended June 30, 2021 and 2020, respectively, and $16.3 million and $19.0 million for the six months ended June 30, 2021 and 2020, respectively. The decreases between periods were primarily due to lower sales volumes.

Taxes Other Than Income

Taxes other than income includes production, ad valorem and franchise taxes. Taxes other than income increased $12.0 million (116%) and $11.3 million (38%) during the three and six months ended June 30, 2021, respectively, compared to the same prior-year periods, due primarily to an increase in production taxes resulting from higher oil and natural gas revenues.

General and Administrative Expenses ("G&A")

	Successor	Predecessor	Successor	Predecessor
In thousands, except per-BOE data and employees	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Cash administrative costs	$ 12,898	$ 22,689	$ 27,201	$ 29,969
Stock-based compensation	2,552	1,087	20,232	3,540
G&A expense	$ 15,450	$ 23,776	$ 47,433	$ 33,509
G&A per BOE				
Cash administrative costs	$ 2.89	$ 4.97	$ 3.11	$ 3.10
Stock-based compensation	0.57	0.24	2.32	0.37
G&A expenses	$ 3.46	$ 5.21	$ 5.43	$ 3.47
Employees as of period end	690	686		

Our G&A expense on an absolute-dollar basis was $15.5 million during the three months ended June 30, 2021, a decrease of $8.3 million (35%) from the same prior-year period, primarily due to modifications in our compensation program during the second quarter of 2020 which resulted in adjustments to the bonus program for 2020, as well as certain severance-related costs recorded during the second quarter of 2020. During the six months ended June 30, 2021, our G&A expense increased $13.9 million (42%) primarily due to $15.3 million of stock-based compensation expense in the first quarter of 2021 resulting from the full vesting of performance-based equity awards with vesting parameters tied to the Company's common stock trading prices. The shares underlying these awards are not currently outstanding as actual delivery of the shares is not scheduled to occur until after the end of the performance period, December 4, 2023.

Interest and Financing Expenses

In thousands, except per-BOE data and interest rates	Successor Three Months Ended June 30, 2021	Predecessor Three Months Ended June 30, 2020	Successor Six Months Ended June 30, 2021	Predecessor Six Months Ended June 30, 2020
Cash interest[1]	$ 1,735	$ 45,263	$ 3,669	$ 91,089
Less: interest not reflected as expense for financial reporting purposes[1]	—	(20,912)	—	(42,266)
Noncash interest expense	685	1,061	1,370	2,092
Amortization of debt discount[2]	—	3,934	—	7,829
Less: capitalized interest	(1,168)	(8,729)	(2,251)	(18,181)
Interest expense, net	$ 1,252	$ 20,617	$ 2,788	$ 40,563
Interest expense, net per BOE	$ 0.28	$ 4.51	$ 0.32	$ 4.20
Average debt principal outstanding[3]	$ 107,542	$ 2,185,029	$ 121,392	$ 2,186,322
Average cash interest rate[4]	6.5 %	8.3 %	6.0 %	8.3 %

(1) Cash interest during the Predecessor period includes the portion of interest on certain debt instruments accounted for as a reduction of debt for GAAP financial reporting purposes in accordance with FASC 470-60, *Troubled Debt Restructuring by Debtors*. The portion of interest treated as a reduction of debt related to the Predecessor's 9% Senior Secured Second Lien Notes due 2021 (the "2021 Notes") and 9¼% Senior Secured Second Lien Notes due 2022 (the "2022 Notes"). Amounts related to the 2021 Notes and 2022 Notes remaining in future interest payable were written-off on July 30, 2020 (the "Petition Date").

(2) Represents amortization of debt discounts during the Predecessor period related to the 7¾% Senior Secured Second Lien Notes due 2024 (the "7¾% Senior Secured Notes") and 6⅜% Convertible Senior Notes due 2024 (the "2024 Convertible Senior Notes"). Remaining debt discounts were written-off on the Petition Date.

(3) Excludes debt discounts related to the Predecessor's 7¾% Senior Secured Notes and 2024 Convertible Senior Notes.

(4) Includes commitment fees but excludes debt issue costs and amortization of discount.

Cash interest during the three and six months ended June 30, 2021 decreased $43.5 million (96%) and $87.4 million (96%), respectively, when compared to the same prior-year periods. The decreases between periods were primarily due to a decrease in the average debt principal outstanding, with the Successor periods reflecting the full extinguishment of all outstanding obligations under our previously outstanding senior secured second lien notes, convertible senior notes, and senior subordinated notes on the Emergence Date, pursuant to the terms of the prepackaged joint plan of reorganization, relieving us of approximately $2.1 billion of debt by issuing equity and/or warrants in the Successor period to the holders of that debt.

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

	Successor	Predecessor	Successor	Predecessor
In thousands, except per-BOE data	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Oil and natural gas properties	$ 28,550	$ 40,290	$ 60,565	$ 82,859
CO_2 properties, pipelines, plants and other property and equipment	7,831	15,124	15,266	32,049
Accelerated depreciation charge(1)	—	—	—	37,368
Total DD&A	$ 36,381	$ 55,414	$ 75,831	$ 152,276
DD&A per BOE				
Oil and natural gas properties	$ 6.39	$ 8.82	$ 6.94	$ 8.58
CO_2 properties, pipelines, plants and other property and equipment	1.75	3.31	1.74	3.31
Accelerated depreciation charge(1)	—	—	—	3.87
Total DD&A cost per BOE	$ 8.14	$ 12.13	$ 8.68	$ 15.76
Write-down of oil and natural gas properties	$ —	$ 662,440	$ 14,377	$ 734,981

(1) Represents an accelerated depreciation charge related to capitalized amounts associated with unevaluated properties that were transferred to the full cost pool.

The decreases in DD&A expense during the three and six months ended June 30, 2021, when compared to the same periods in 2020, were primarily due to lower depletable costs due to the step down in book value resulting from fresh start accounting as of September 18, 2020, with the year-over-year decrease further impacted by accelerated depreciation of $37.4 million in the first quarter of 2020 related to unevaluated properties that were transferred to the full cost pool.

Full Cost Pool Ceiling Test Write-Downs

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period. We recognized a full cost pool ceiling test write-down of $14.4 million during the three months ended March 31, 2021, with first-day-of-the-month NYMEX oil prices for the preceding 12 months averaging $36.40 per Bbl, after adjustments for market differentials and transportation expenses by field. The write-down was primarily a result of the recent acquisition (see *Overview – March 2021 Acquisition of Wyoming CO_2 EOR Fields*) which was recorded based on a valuation that utilized NYMEX strip oil prices at the acquisition date, which were significantly higher than the average first-day-of-the-month NYMEX oil prices used to value the cost ceiling. We also recognized full cost pool ceiling test write-downs of $662.4 million and $72.5 million during the Predecessor three months ended June 30, 2020 and March 31, 2020, respectively. We did not record a ceiling test write-down during the three months ended June 30, 2021.

Income Taxes

	Successor	Predecessor	Successor	Predecessor
In thousands, except per-BOE amounts and tax rates	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Current income tax expense (benefit)	$ (260)	$ 598	$ (451)	$ (5,809)
Deferred income tax benefit	(36)	(102,304)	(87)	(106,513)
Total income tax benefit	$ (296)	$ (101,706)	$ (538)	$ (112,322)
Average income tax benefit per BOE	$ (0.07)	$ (22.27)	$ (0.06)	$ (11.63)
Effective tax rate	0.4 %	12.7 %	0.4 %	15.3 %
Total net deferred tax liability	$ 1,187	$ 306,186		

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 combined federal and state statutory rate of approximately 25% in 2021 and 2020. Our effective tax rates for the Successor three and six months ended June 30, 2021 were significantly lower than our estimated statutory rate, primarily due to our overall deferred tax asset position and the valuation allowance offsetting those assets. As we had a pre-tax loss for the second quarter of 2021 and first half of 2021, the income tax benefit resulting from these losses is fully offset by the change in valuation allowance, resulting in essentially no tax provision.

The tax basis of our assets, primarily our oil and gas properties, is in excess of their carrying value, as adjusted in fresh start accounting; therefore, we are currently in a net deferred tax asset position. Based on all available evidence, both positive and negative, we continue to record a valuation allowance on our underlying deferred tax assets as of June 30, 2021, as we believe our deferred tax assets are not more-likely-than-not to be realized. We intend to maintain the valuation allowances on our deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of the allowances, which will largely be determined based on oil prices and the Company's ability to generate positive pre-tax income. A $1.2 million state deferred tax liability is recorded on the Successor balance sheet.

The current income tax benefits for the Predecessor six months ended June 30, 2020, represent amounts estimated to be receivable resulting from alternative minimum tax credits.

As of June 30, 2021, we had $0.6 million of alternative minimum tax credits, which under the Tax Cut and Jobs Act will be refunded in 2021 and are recorded as a receivable on the balance sheet. Our state net operating loss carryforwards expire in various years, starting in 2025.

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	2021	2020	2021	2020
Oil and natural gas revenues	$ 63.23	$ 23.95	$ 59.33	$ 35.09
Receipt (payment) on settlements of commodity derivatives	(14.17)	9.99	(11.65)	7.28
Lease operating expenses	(24.65)	(17.80)	(22.01)	(19.73)
Production and ad valorem taxes	(4.88)	(1.92)	(4.55)	(2.77)
Transportation and marketing expenses	(1.91)	(2.06)	(1.87)	(1.97)
Production netback	17.62	12.16	19.25	17.90
CO_2 sales, net of operating and discovery expenses	1.93	1.23	1.93	1.33
General and administrative expenses[(1)]	(3.46)	(5.21)	(5.43)	(3.47)
Interest expense, net	(0.28)	(4.51)	(0.32)	(4.20)
Stock compensation and other	0.12	(1.71)	1.95	0.22
Changes in assets and liabilities relating to operations	4.40	0.44	(0.94)	(4.24)
Cash flows from operations	20.33	2.40	16.44	7.54
DD&A – excluding accelerated depreciation charge	(8.14)	(12.13)	(8.68)	(11.89)
DD&A – accelerated depreciation charge[(2)]	—	—	—	(3.87)
Write-down of oil and natural gas properties	—	(145.04)	(1.65)	(76.08)
Deferred income taxes	0.01	22.40	0.01	11.03
Gain on extinguishment of debt	—	—	—	1.97
Noncash fair value gains (losses) on commodity derivatives	(24.45)	(18.78)	(21.37)	3.76
Other noncash items	(5.13)	(1.56)	(1.62)	3.00
Net loss	$ (17.38)	$ (152.71)	$ (16.87)	$ (64.54)

(1) General and administrative expenses include $15.3 million of performance stock-based compensation related to the full vesting of outstanding performance awards during the six months ended June 30, 2021, resulting in a significant non-recurring expense, which if excluded, would have caused these expenses to average $3.68 per BOE.
(2) Represents an accelerated depreciation charge related to impaired unevaluated properties that were transferred to the full cost pool.

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*, regarding possible or assumed future results of operations and cash flows, and other plans and objectives for the future operations of Denbury, projections or assumptions as to general economic conditions, predictions as to the nature and economics of a carbon capture, use and storage industry ("CCUS"), and anticipated effects of COVID-19 on U.S. and global oil

demand 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, the level and sustainability of the recent recovery in worldwide oil prices from their COVID-19 coronavirus caused downturn, financial forecasts, future hydrocarbon prices and their volatility, current or future liquidity sources or their adequacy to support our anticipated future activities, statements or predictions related to the scope, timing and economic aspects of the carbon capture, use and storage industry or results of negotiations of CCUS arrangements, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected production levels, 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, price and availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, production, drilling activity or methods, including the timing and location thereof, the nature of any future asset purchases or sales or the timing or proceeds thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, including Cedar Creek Anticline ("CCA"), or its 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, the impact of regulatory rulings or changes, outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions, and other variables surrounding 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 are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and 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 produced; 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; success of our risk management techniques; accuracy of our cost estimates; access to and 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 cybersecurity breaches, or from well incidents, hurricanes, tropical storms, floods, 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.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Debt and Interest Rate Sensitivity

As of June 30, 2021, we had $35.0 million of outstanding borrowings under our Bank Credit Agreement. 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. Our Bank Credit Agreement does not have any triggers or covenants regarding our debt ratings with rating agencies. The following table presents the principal and fair values of our outstanding debt as of June 30, 2021:

In thousands	2021	2022	2023	2024	Total	Fair Value
Variable rate debt:						
Senior Secured Bank Credit Facility (weighted average interest rate of 4.0% at June 30, 2021)	$ —	$ —	$ —	$ 35,000	$ 35,000	$ 35,000

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 addition, our new senior secured bank credit facility entered into on the Emergence Date required that, by December 31, 2020, we have certain minimum commodity hedge levels in place covering anticipated crude oil production through July 31, 2022. The requirement is non-recurring, and we were in compliance with the hedging requirements as of December 31, 2020. 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 2022 using NYMEX fixed-price swaps and costless collars. Depending on market conditions, we may continue to add to our existing 2021 and 2022 hedges. See also Note 6, *Commodity Derivative Contracts*, and Note 7, *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.

At June 30, 2021, our commodity derivative contracts were recorded at their fair value, which was a net liability of $245.4 million, a $109.3 million increase from the $136.1 million net liability recorded at March 31, 2021, and a $186.6 million increase from the $58.8 million net liability recorded at December 31, 2020. These changes are primarily related to the expiration of commodity derivative contracts during the three and six months ended June 30, 2021, new commodity derivative contracts entered into during 2021 for future periods, and to the changes in oil futures prices from period to period.

Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil futures prices as of June 30, 2021, and assuming both a 10% increase and decrease thereon, we would expect to make payments on our crude oil derivative contracts outstanding at June 30, 2021 as shown in the following table:

	Receipt / (Payment)
In thousands	Crude Oil Derivative Contracts
Based on:	
Futures prices as of June 30, 2021	$ (234,002)
10% increase in prices	(326,894)
10% decrease in prices	(152,780)

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.

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, 2021, 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 2021, 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.

Denbury Inc.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information under Note 8, *Commitments and Contingencies*, to the Unaudited Condensed Consolidated Financial Statements is incorporated herein by reference.

Item 1A. Risk Factors

Please refer to Part I, Item 1A of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2020. There have been no material changes to our risk factors contained in our Annual Report on Form 10-K for the year ended December 31, 2020.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No.	Exhibit
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.INS*	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	The cover page from the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, has been formatted in Inline XBRL.

* Included herewith.
** Furnished herewith in accordance with Item 601(b)(32) of Regulation S-K.

Denbury Inc.

SIGNATURES

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

DENBURY INC.

August 5, 2021	/s/ Mark C. Allen
	Mark C. Allen Executive Vice President and Chief Financial Officer
August 5, 2021	/s/ Nicole Jennings
	Nicole Jennings Vice President and Chief Accounting Officer

Exhibit 31(a)

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

I, Chris Kendall, certify that:

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

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

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

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

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

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

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

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

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

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

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

August 5, 2021

/s/ Chris Kendall

Chris Kendall

President and Chief Executive Officer

Exhibit 31(b)

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

I, Mark C. Allen, certify that:

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

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

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

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

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

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

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

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

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

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

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

August 5, 2021

/s/ Mark Allen

Mark C. Allen

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

Exhibit 32

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

In connection with the accompanying Quarterly Report on Form 10-Q for the quarter ended June 30, 2021 (the Report) of Denbury Inc. (Denbury) as filed with the Securities and Exchange Commission, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

Dated: August 5, 2021

/s/ Chris Kendall
Chris Kendall
President and Chief Executive Officer

Dated: August 5, 2021

/s/ Mark C. Allen
Mark C. Allen
Executive Vice President, Chief Financial Officer,
Treasurer, and Assistant Secretary