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 September 30, 2022
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

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 October 31, 2022, was 49,800,113.

Denbury Inc.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2022	December 31, 2021
Assets		
Current assets		
Cash and cash equivalents	$ 519	$ 3,671
Accrued production receivable	176,249	143,365
Trade and other receivables, net	19,035	19,270
Derivative assets	26,782	—
Prepaids	27,060	9,099
Total current assets	249,645	175,405
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	1,325,866	1,109,011
Unevaluated properties	192,784	112,169
CO_2 properties	187,690	183,369
Pipelines	219,090	224,394
CCUS storage sites and related assets	32,348	—
Other property and equipment	102,627	93,950
Less accumulated depletion, depreciation, amortization and impairment	(270,593)	(181,393)
Net property and equipment	1,789,812	1,541,500
Operating lease right-of-use assets	17,065	19,502
Derivative assets	9,048	—
Intangible assets, net	81,410	88,248
Restricted cash for future asset retirement obligations	47,633	46,673
Other assets	48,718	31,625
Total assets	$ 2,243,331	$ 1,902,953
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 259,015	$ 191,598
Oil and gas production payable	89,311	75,899
Derivative liabilities	33,868	134,509
Operating lease liabilities	4,392	4,677
Total current liabilities	386,586	406,683
Long-term liabilities		
Long-term debt, net of current portion	15,000	35,000
Asset retirement obligations	301,764	284,238
Deferred tax liabilities, net	54,940	1,638
Operating lease liabilities	14,726	17,094
Other liabilities	17,438	22,910
Total long-term liabilities	403,868	360,880
Commitments and contingencies (Note 9)		
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; 49,793,270 and 50,193,656 shares issued, respectively	50	50
Paid-in capital in excess of par	1,042,438	1,129,996
Retained earnings	410,389	5,344
Total stockholders' equity	1,452,877	1,135,390
Total liabilities and stockholders' equity	$ 2,243,331	$ 1,902,953

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	**2021**	**2022**	**2021**
Revenues and other income				
Oil, natural gas, and related product sales	$ 395,223	$ 308,454	$ 1,232,104	$ 826,607
CO_2 sales and transportation fees	18,586	12,237	44,618	31,599
Oil marketing revenues	17,663	12,593	47,725	26,538
Other income	8,015	10,451	9,055	11,518
Total revenues and other income	439,487	343,735	1,333,502	896,262
Expenses				
Lease operating expenses	134,464	116,536	376,643	308,731
Transportation and marketing expenses	5,191	5,985	14,638	22,304
CO_2 operating and discovery expenses	2,066	1,963	6,564	4,487
Taxes other than income	33,789	24,154	101,487	65,499
Oil marketing purchases	19,095	11,940	47,162	25,763
General and administrative expenses	21,071	15,388	58,998	62,821
Interest, net of amounts capitalized of $1,044, $1,249, $3,177 and $3,500, respectively	909	669	3,092	3,457
Depletion, depreciation, and amortization	37,680	37,691	108,425	113,522
Commodity derivatives expense (income)	(109,248)	41,745	140,325	330,152
Write-down of oil and natural gas properties	—	—	—	14,377
Other expenses	2,726	4,553	11,459	9,913
Total expenses	147,743	260,624	868,793	961,026
Income (loss) before income taxes	291,744	83,111	464,709	(64,764)
Income tax provision (benefit)	41,321	403	59,664	(135)
Net income (loss)	$ 250,423	$ 82,708	$ 405,045	$ (64,629)
Net income (loss) per common share				
Basic	$ 4.89	$ 1.62	$ 7.86	$ (1.27)
Diluted	$ 4.66	$ 1.51	$ 7.43	$ (1.27)
Weighted average common shares outstanding				
Basic	51,182	51,094	51,512	50,807
Diluted	53,715	54,714	54,524	50,807

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30,	
	2022	2021
Cash flows from operating activities		
Net income (loss)	$ 405,045	$ (64,629)
Adjustments to reconcile net income (loss) to cash flows from operating activities		
Depletion, depreciation, and amortization	108,425	113,522
Write-down of oil and natural gas properties	—	14,377
Deferred income taxes	53,301	(34)
Stock-based compensation	11,491	22,788
Commodity derivatives expense	140,325	330,152
Payment on settlements of commodity derivatives	(276,796)	(179,466)
Debt issuance costs	2,465	2,055
Gain from asset sales and other	(1,119)	(7,026)
Other, net	(11,543)	(2,448)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	(32,884)	(52,948)
Trade and other receivables	66	(1,809)
Other current and long-term assets	(21,729)	7,337
Accounts payable and accrued liabilities	28,359	47,484
Oil and natural gas production payable	13,412	23,168
Asset retirement obligations and other liabilities	(22,409)	(4,966)
Net cash provided by operating activities	396,409	247,557
Cash flows from investing activities		
Oil and natural gas capital expenditures	(217,834)	(113,041)
CCUS storage sites and related capital expenditures	(27,518)	—
Acquisitions of oil and natural gas properties	(874)	(10,927)
Pipelines and plants capital expenditures	(22,259)	(19,123)
Net proceeds from sales of oil and natural gas properties and equipment	237	19,053
Equity investment	(10,000)	—
Other	(9,746)	5,797
Net cash used in investing activities	(287,994)	(118,241)
Cash flows from financing activities		
Bank repayments	(808,000)	(697,000)
Bank borrowings	788,000	627,000
Pipeline financing repayments	—	(50,676)
Common stock repurchase program	(100,028)	—
Other	9,421	(2,426)
Net cash used in financing activities	(110,607)	(123,102)
Net increase (decrease) in cash, cash equivalents, and restricted cash	(2,192)	6,214
Cash, cash equivalents, and restricted cash at beginning of period	50,344	42,248
Cash, cash equivalents, and restricted cash at end of period	$ 48,152	$ 48,462

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	Treasury Stock (at cost)		Total Equity
	Shares	Amount			Shares	Amount	
Balance – December 31, 2021	50,193,656	$ 50	$ 1,129,996	$ 5,344	—	$ —	$ 1,135,390
Issued pursuant to stock compensation plans	141,581	—	—	—	—	—	—
Stock-based compensation	—	—	3,142	—	—	—	3,142
Tax withholding for stock compensation plans	—	—	(58)	—	—	—	(58)
Issued pursuant to exercise of warrants	14,153	—	47	—	—	—	47
Net loss	—	—	—	(872)	—	—	(872)
Balance – March 31, 2022	50,349,390	50	1,133,127	4,472	—	—	1,137,649
Stock repurchase program	(457,549)	—	—	—	457,549	(28,751)	(28,751)
Forfeited pursuant to stock compensation plans	(3,264)	—	—	—	—	—	—
Stock-based compensation	—	—	4,400	—	—	—	4,400
Tax withholding for stock compensation plans	—	—	(5)	—	—	—	(5)
Issued pursuant to exercise of warrants	987,411	1	53	—	—	—	54
Net income	—	—	—	155,494	—	—	155,494
Balance – June 30, 2022	50,875,988	51	1,137,575	159,966	457,549	(28,751)	1,268,841
Stock repurchase program	(1,157,807)	—	—	—	1,157,807	(71,277)	(71,277)
Net issued pursuant to stock compensation plans	3,684	—	—	—	—	—	—
Stock-based compensation	—	—	4,691	—	—	—	4,691
Retired Treasury Shares	—	(1)	(100,029)	—	(1,615,391)	100,030	—
Tax withholding for stock compensation plans	(35)	—	—	—	35	(2)	(2)
Issued pursuant to exercise of warrants	71,440	—	201	—	—	—	201
Net income	—	—	—	250,423	—	—	250,423
Balance – September 30, 2022	49,793,270	$ 50	$ 1,042,438	$ 410,389	—	$ —	$ 1,452,877

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Treasury Stock (at cost)		Total Equity
	Shares	Amount			Shares	Amount	
Balance – December 31, 2020	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	—	195	—	—	—	195
Net loss	—	—	—	(69,642)	—	—	(69,642)
Balance – March 31, 2021	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	—	292	—	—	—	292
Net loss	—	—	—	(77,695)	—	—	(77,695)
Balance – June 30, 2021	50,017,491	50	1,125,143	(197,995)	—	—	927,198
Stock-based compensation	—	—	2,686	—	—	—	2,686
Issued pursuant to exercise of warrants	103,404	—	201	—	—	—	201
Net income	—	—	—	82,708	—	—	82,708
Balance – September 30, 2021	50,120,895	$ 50	$ 1,128,030	$ (115,287)	—	$ —	$ 1,012,793

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., a Delaware corporation, is an independent energy company with operations focused in the Gulf Coast and Rocky Mountain regions of the United States. 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.

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, 2021 (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 September 30, 2022, our consolidated results of operations for the three and nine months ended September 30, 2022 and 2021, our consolidated cash flows for the nine months ended September 30, 2022 and 2021, and our consolidated statements of changes in stockholders' equity for the three and nine months ended September 30, 2022 and 2021.

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:

In thousands	September 30, 2022	December 31, 2021
Cash and cash equivalents	$ 519	$ 3,671
Restricted cash for future asset retirement obligations	47,633	46,673
Total cash, cash equivalents, and restricted cash shown in the Unaudited Condensed Consolidated Statements of Cash Flows	$ 48,152	$ 50,344

Restricted cash for future asset retirement obligations in the table above consists of escrow accounts that are legally restricted for certain of our asset retirement obligations.

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. Basic weighted average common shares exclude shares of nonvested restricted stock (although nonvested restricted stock is issued and outstanding upon grant). As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income (loss) per common share. Restricted stock units and performance stock units are also excluded from basic weighted average common shares outstanding until the vesting date. Basic weighted average common shares during the three and nine months ended September 30, 2022 includes 1,404,649 performance-based and restricted stock units which are fully vested as of September 30, 2022; however, the shares underlying these stock units are not included in shares currently issued or outstanding as actual delivery of the shares is not scheduled to occur until December 4, 2023.

Diluted net income (loss) per common share is calculated in the same manner but includes the impact of all potentially dilutive securities. Potentially dilutive securities include restricted stock, restricted stock units, performance stock units, shares to be issued under the employee stock purchase plan ("ESPP"), and series A and series B warrants.

For each of the three and nine months ended September 30, 2022 and 2021, there were no adjustments to net income (loss) for purposes of calculating basic and diluted net income (loss) per common share.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2022	2021	2022	2021
Weighted average common shares outstanding – basic	51,182	51,094	51,512	50,807
Effect of potentially dilutive securities				
Restricted stock, restricted stock units and performance stock units	664	908	615	—
Warrants	1,869	2,712	2,397	—
Weighted average common shares outstanding – diluted	53,715	54,714	54,524	50,807

For the nine months ended September 30, 2021, the weighted average common shares outstanding used to calculate basic earnings per share and diluted earnings per share were the same, since the Company recorded a net loss for the period. Assuming the Company had recorded net income during the nine months ended September 30, 2021, the weighted average diluted shares outstanding would have been 53.4 million (including the impact of 0.8 million restricted stock units and 1.8 million shares with respect to warrants).

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

	September 30,	
In thousands	2022	2021
Restricted stock, restricted stock units and performance stock units	63	1,255
Warrants	—	5,314
Employee Stock Purchase Plan	8	—

At September 30, 2022, the Company had approximately 3.2 million warrants outstanding that can be exercised for shares of our common stock, at an exercise price of $32.59 per share for the 1.8 million Series A warrants outstanding and at an exercise price of $35.41 per share for the 1.4 million Series B warrants outstanding. The warrants may be exercised for cash or on a cashless basis. The Series A warrants are exercisable until September 18, 2025, and the Series B warrants are exercisable until September 18, 2023, at which times the warrants expire. During the three and nine months ended September 30, 2022, 119,367 and 1,941,380 warrants were exercised for a total of 71,440 shares and 1,073,004 shares, respectively, most of which were exercised on a cashless basis.

Oil and Natural Gas Properties

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. The write-down was primarily a result of the March 2021 acquisition of Wyoming CO_2 EOR properties (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 did not record a ceiling test write-down during the three or nine months ended September 30, 2022.

CCUS Storage Sites and Other Assets

Capitalized Costs. We capitalize costs that we incur to acquire and develop storage sites for the injection of CO_2. These costs generally include, or are expected to include, expenditures for acquiring surface and subsurface rights; third-party acquisition costs; permitting; drilling; facilities; environmental monitoring equipment for groundwater and storage site gas; engineering; capitalized interest; on-site road construction and other capital infrastructure costs. If it is determined that a storage site will no longer be pursued, developed or utilized, all previously capitalized costs associated with that site are expensed.

Amortization. Our CCUS storage sites are currently in the development stage and not yet operational. Accordingly, we currently have no amortization of capitalized costs. Amortization of these costs will begin when CO_2 storage operations commence.

Investment in Project Development Company ("Clean Hydrogen Works") of Planned Louisiana Blue Hydrogen Ammonia Project. In September 2022, we made a $10.0 million investment in the project development company of a planned blue hydrogen/ammonia multi-block facility, while also signing a definitive agreement for the transportation and sequestration of CO_2 for the first two blocks of the proposed plant. We have committed to invest another $10.0 million when certain project milestones are achieved. The investment is included in "Other assets" in the Unaudited Condensed Consolidated Balance Sheet as of September 30, 2022.

Note 2. Acquisition and Divestiture

2021 Acquisition of Wyoming CO_2 EOR Properties

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, including surface facilities and a 46-mile CO_2 transportation pipeline to the acquired fields. The acquisition purchase price was $10.9 million (after final closing adjustments) plus two contingent $4 million cash payments if NYMEX WTI oil prices average at least $50 per Bbl during each of 2021 and 2022. We made the first contingent payment in January 2022 and if the price condition is met, the second $4 million payment will be due in January 2023. The fair value of the contingent consideration recorded on our Unaudited Condensed Consolidated Balance Sheets was $3.9 million as of September 30, 2022.

The fair values allocated to our assets acquired and liabilities assumed for the acquisition, based on significant inputs not observable in the market and considered level 3 inputs, were finalized during the third quarter of 2021, after consideration of final closing adjustments and evaluation of reserves and liabilities assumed. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the acquisition:

In thousands		
Consideration:		
Cash consideration	$	10,906
Fair value of assets acquired and liabilities assumed:		
Proved oil and natural gas properties		60,101
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	$	10,906

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 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 proved reserves.

Note 3. Revenue Recognition

We record revenue in accordance with Financial Accounting Standards Board ("FASB") Codification ("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 one 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. In certain situations, the Company enters into marketing arrangements for the purchase and subsequent sale of crude oil from third parties. We recognize the revenues received and the associated expenses incurred on these sales on a gross basis, as "Oil marketing revenues" and "Oil marketing purchases" in our Unaudited Condensed Consolidated Statements of Operations, since 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 for the three and nine months ended September 30, 2022 and 2021:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2022	2021	2022	2021
Oil sales	$ 389,543	$ 305,093	$ 1,217,377	$ 818,714
Natural gas sales	5,680	3,361	14,727	7,893
CO_2 sales and transportation fees	18,586	12,237	44,618	31,599
Oil marketing revenues	17,663	12,593	47,725	26,538
Total revenues	$ 431,472	$ 333,284	$ 1,324,447	$ 884,744

Note 4. Long-Term Debt

Senior Secured Bank Credit Agreement

On September 18, 2020, we entered into a $575 million credit agreement for a senior secured revolving credit facility with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined semiannually on or around May 1 and November 1 of each year. 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 undrawn portion of the aggregate lender commitments under the Bank Credit Agreement is subject to a commitment fee of 0.5% per annum. Our outstanding borrowings under the Bank Credit Agreement, totaled $15.0 million and $35.0 million as of September 30, 2022 and December 31, 2021, respectively.

On May 4, 2022, we entered into a Second Amendment to the Bank Credit Agreement, which among other things:

- Increased the borrowing base and lender commitments from $575 million to $750 million;
- Extended the maturity date from January 30, 2024 to May 4, 2027;
- Modified the interest provisions on loans under the Bank Credit Agreement to (1) reduce the applicable margin for alternate base rate loans from 2% to 3% per annum to 1.5% to 2.5% per annum and (2) replace provisions referencing LIBOR loans with Secured Overnight Financing Rate loans, with an applicable margin of 2.5% to 3.5% per annum; and
- Permitted us to pay dividends on our common stock and make other unlimited restricted payments and investments so long as (1) no event of default or borrowing base deficiency exists; (2) our total leverage ratio is 1.5 to 1 or lower; and (3) availability under the Bank Credit Agreement is at least 20% of the borrowing base.

As part of our Fall 2022 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $750 million, with our next scheduled redetermination around May 1, 2023.

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 certain exceptions to such limitations, as specified in the Bank Credit Agreement. Our Bank Credit Agreement required certain minimum commodity hedge levels in connection with our emergence from bankruptcy; however, these conditions were met as of December 31, 2020, and we currently have no ongoing hedging requirements under the Bank Credit Agreement.

The 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.

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 September 30, 2022, 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 and amendments thereto.

Note 5. Stockholders' Equity

Share Repurchase Program

In early May 2022, our Board of Directors authorized a common share repurchase program for up to $250 million of outstanding Denbury common stock. During June and July 2022, the Company repurchased 1,615,356 shares of Denbury common stock under this program for approximately $100 million, at an average price of $61.92 per share. In August 2022, the Board increased Denbury's stock repurchase authorization by $100 million, thus a total of $250.0 million of common stock currently remains authorized for future repurchases under this program. The program has no pre-established ending date and may be suspended or discontinued at any time. The Company is not obligated to repurchase any dollar amount or specific number of shares of its common stock under the program.

Retirement of Treasury Stock

During the quarter ended September 30, 2022, we retired 1.6 million shares of existing treasury stock, with a carrying value of $100.0 million, acquired primarily through our stock repurchase program. Upon the retirement of treasury stock, we reduce common stock by the par value of common stock retired, and we reduce additional paid-in capital by the value of those shares in excess of par value.

Employee Stock Purchase Plan

On June 1, 2022, the Company's stockholders approved the Denbury Inc. Employee Stock Purchase Plan authorizing the sale of up to 2,000,000 shares of common stock thereunder. In accordance with the ESPP, full-time employees may contribute up to 10% of their base salary, subject to certain limitations, to purchase previously unissued Denbury common stock. Participants in the ESPP may purchase common stock at a 15% discount to the fair market value of a share of common stock determined as the lower of the closing sales price on the first or last trading day of each offering period. The first offering period under the ESPP commenced on September 1, 2022 and will end on December 31, 2022. The plan is administered by the Compensation Committee of our Board of Directors.

Note 6. Income Taxes

We make estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Significant judgment is required in estimating valuation allowances, and in making this determination we consider all available positive and negative evidence and make certain assumptions. The realization of a deferred tax asset ultimately depends on the existence of sufficient taxable income in the applicable carryback or carryforward periods. In our assessment, we consider the nature, frequency, and severity of current and cumulative losses, as well as historical and forecasted financial results, the overall business environment, our industry's historic cyclicality, the reversal of existing deferred tax assets and liabilities, and tax planning strategies.

We assess the valuation allowance recorded on our deferred tax assets, which was $125.5 million at December 31, 2021, on a quarterly basis. This valuation allowance on our federal and certain state deferred tax assets was recorded in September 2020 after the application of fresh start accounting, as (1) the tax basis of our assets, primarily our oil and gas properties, was in excess of the carrying value, as adjusted for fresh start accounting and (2) our historical pre-tax income reflected a three-year cumulative loss primarily due to ceiling test write-downs and reorganization items that were recorded in 2020. While we continued to be in a cumulative three-year-loss position through the first quarter of 2022, we initially determined as of March 31, 2022, that there was sufficient positive evidence, primarily related to a substantial increase in worldwide oil prices, to conclude that $64.9 million of our federal and certain state deferred tax assets are more likely than not to be realized. Accordingly, we reversed $5.9 million, $18.8 million and $29.2 million of this valuation allowance during the three months ended March 31, June 30, and September 30, 2022, respectively, and currently expect to reverse the remaining $11.0 million during the fourth quarter of 2022, resulting in a reduction to our annualized effective tax rate. We continue to maintain a valuation allowance of $60.6 million for certain state tax benefits that we currently do not expect to realize before their expiration.

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 2022 and 2021. Our effective tax rate for the three and nine months ended September 30, 2022 was significantly lower than our estimated statutory rate primarily due to the release of the valuation allowance that was recorded in the three and nine months ended September 30, 2022.

Note 7. 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, costless collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength and expectation of future commodity prices.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification, and all of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement (or affiliates of such lenders). As of September 30, 2022, 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 September 30, 2022, 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)	Swap	Floor	Ceiling
Oil Contracts:					
2022 Fixed-Price Swaps					
Oct – Dec	NYMEX	9,500	$ 57.52	$ —	$ —
2022 Costless Collars					
Oct – Dec	NYMEX	11,500	$ —	$ 52.39	$ 67.29
2023 Fixed-Price Swaps					
Jan – June	NYMEX	7,500	$ 75.29	$ —	$ —
July – Dec	NYMEX	5,000	76.26	—	—
2023 Costless Collars					
Jan – June	NYMEX	17,500	$ —	$ 69.71	$ 100.42
July – Dec	NYMEX	9,000	—	68.33	100.69

Note 8. 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 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
September 30, 2022				
Assets				
Oil derivative contracts – current	$ —	$ 26,782	$ —	$ 26,782
Oil derivative contracts – long-term	—	9,048	—	9,048
Total Assets	$ —	$ 35,830	$ —	$ 35,830
Liabilities				
Oil derivative contracts – current	$ —	$ (33,868)	$ —	$ (33,868)
Oil derivative contracts – long-term	—	—	—	—
Total Liabilities	$ —	$ (33,868)	$ —	$ (33,868)
December 31, 2021				
Liabilities				
Oil derivative contracts – current	$ —	$ (134,509)	$ —	$ (134,509)
Total Liabilities	$ —	$ (134,509)	$ —	$ (134,509)

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 September 30, 2022 and December 31, 2021 was $15.0 million and $35.0 million, respectively. 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 9. Commitments and Contingencies

Litigation and Regulatory Proceedings

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 and regulatory proceedings are 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.

On May 26, 2022, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order ("NOPV") relating to the February 2020 pipeline failure near Satartia, Mississippi in our CO_2 pipeline running between the Tinsley and Delhi fields. The NOPV proposed a preliminarily assessed civil penalty of $3.9 million in connection with the incident, which we recorded in our second quarter of 2022 financial statements. We have responded to the NOPV and are pursuing discussions with PHMSA regarding the probable violations alleged in the NOPV, the proposed civil penalty, and the nature of the compliance order contained in the NOPV.

Note 10. Additional Balance Sheet Details

Accounts Payable and Accrued Liabilities

In thousands	September 30, 2022	December 31, 2021
Accounts payable	$ 61,643	$ 25,700
Accrued derivative settlements	13,378	27,336
Accrued lease operating expenses	32,507	27,901
Accrued asset retirement obligations – current	40,000	18,373
Accrued compensation	30,963	23,735
Taxes payable	18,823	14,453
Accrued exploration and development costs	18,418	18,936
Other	43,283	35,164
Total	$ 259,015	$ 191,598

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, 2021 (the "Form 10-K"), along with *Management's Discussion and Analysis of Financial Condition and Results of Operations* contained in the Form 10-K. Any terms used but not defined herein have the same meaning given to them in the Form 10-K.

Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with *Risk Factors* under Item 1A of the Form 10-K, along with *Forward-Looking Information* at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

OVERVIEW

Denbury is an independent 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, making the Company's Scope 1 and 2 CO_2 emissions negative today, with a goal to be net-zero on its Scope 1, 2, and 3 CO_2 emissions by 2030, primarily through increasing the amount of captured industrial-sourced CO_2 used in its operations.

Carbon Capture, Use and Storage. CCUS is a process that captures CO_2 from industrial sources and either reuses 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. During the nine months ended September 30, 2022, approximately 39% of the CO_2 utilized in our oil and gas operations was industrial-sourced CO_2, equivalent to an annualized average usage rate of over 4 million metric tons in 2022. This compares to 34% utilized during the nine months ended September 30, 2021, with the increase related to commencing CO_2 injection in the first phase of our Cedar Creek Anticline ("CCA") EOR project. 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 lead in the emerging CCUS industry, as the building of a permanent carbon capture and sequestration business by others requires both time and capital to build assets such as those we own and have been operating for years.

We have been seeking to build our CCUS business and pursue new CCUS opportunities on two fronts: first, we have been engaged with existing and potential third-party industrial CO_2 emitters regarding CO_2 transportation and storage solutions under long term agreements; second, we have been identifying and securing potential future sequestration sites for permanent storage. We continue to make material progress in both of these pursuits, and we currently have signed term sheets and definitive agreements for the potential future transportation and storage of up to 20 million tons of CO_2 per annum from the planned capture of CO_2 emissions from existing and proposed industrial plants. On the sequestration front, we have also signed agreements securing the rights to five future sequestration sites which we believe have the potential to store up to 1.5 billion metric tons of CO_2.

While our use of CO_2 in EOR is the only CCUS operation reflected in our historical financial and operational results (as a cost), we believe the incentives offered under Section 45Q of the Internal Revenue Code and the expansion of those incentives under the August 2022 Inflation Reduction Act will drive demand for CCUS and allow us to collect a fee for the transportation and storage of captured industrial-sourced CO_2, including CO_2 utilized in our EOR operations. Although we believe our first revenues associated with the sequestration of CO_2 will likely occur in 2024 or 2025, we are currently incurring costs to develop and permit storage sites and will continue to advance those efforts over the next several years. During the nine months ended September 30, 2022, we capitalized $32.3 million in "CCUS storage sites and related assets" in our Unaudited Condensed Consolidated Balance Sheets, primarily consisting of acquisition costs associated with sequestration sites. In addition, during the third quarter we made a $10.0 million investment in the project development company ("Clean Hydrogen Works") of a planned blue hydrogen/ammonia multi-block facility, while also signing a definitive agreement for the transportation and sequestration of CO_2 for the first two blocks of the proposed plant. The investment is included in "Other assets" in the

Unaudited Condensed Consolidated Balance Sheet as of September 30, 2022. We have committed to invest another $10 million when certain project milestones are achieved.

Oil Price Impact on Our Business. Our financial results are significantly impacted by changes in oil prices, as 97% of our sales volumes are 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. Oil prices have historically been volatile and can fluctuate significantly over short periods of time. For example, average NYMEX WTI oil prices increased from the mid-$70s per Bbl range in the fourth quarter of 2021 to an average of approximately $109 per Bbl during the second quarter of 2022 before declining to an average of approximately $91 per Bbl during the third quarter of 2022. The increases in oil prices from 2021 levels were due in part to worldwide oil supply disruptions associated with the Russian invasion of Ukraine.

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 quarterly periods:

	Three Months Ended				
In thousands, except per-unit data	Sept. 30, 2022	June 30, 2022	March 31, 2022	Dec. 31, 2021	Sept. 30, 2021
Oil, natural gas, and related product sales	$ 395,223	$ 451,970	$ 384,911	$ 333,348	$ 308,454
Payment on settlements of commodity derivatives	(55,780)	(127,959)	(93,057)	(97,774)	(77,670)
Oil, natural gas, and related product sales and commodity derivative settlements, combined	$ 339,443	$ 324,011	$ 291,854	$ 235,574	$ 230,784
Average daily sales (BOE/d)	47,109	$ 46,561	46,925	48,882	49,682
Average net realized oil prices					
Oil price per Bbl - excluding impact of derivative settlements	$ 92.77	$ 108.81	$ 93.17	$ 75.68	$ 68.88
Oil price per Bbl - including impact of derivative settlements	79.49	77.63	70.43	53.21	51.35

As shown in the table above, our oil and natural gas revenues have increased dramatically during 2022 due to the increase in oil prices. However, the benefit of the increase in revenues during the first half of 2022 was offset in part by the impact of higher cash payments on our commodity derivative contracts which were settled during that period. These contracts were largely required to be entered into during the fourth quarter of 2020 under the one-time requirement of our September 18, 2020 bank credit facility. During the third quarter of 2022, less of our production was hedged, and our hedges for the second half of 2022 are at more favorable prices and with a greater mix of collars, providing the potential for us to realize a greater portion of increased oil prices. We paid $55.8 million during the third quarter of 2022 related to the expiration of commodity derivative contracts and expect to make additional payments on the settlement of our contracts expiring during the remainder of 2022.

Third Quarter 2022 Financial Results and Highlights. We recognized net income of $250.4 million, or $4.66 per diluted common share, during the third quarter of 2022, compared to a net income of $82.7 million, or $1.51 per diluted common share, during the third quarter of 2021. The primary drivers of the comparative third quarter operating results include the following:

- Oil and natural gas revenues increased $86.8 million (28%) due primarily to an increase in oil prices;
- Commodity derivatives expense decreased by $151.0 million consisting of a $129.1 million increase in noncash fair value changes ($165.0 million gain during the third quarter of 2022 compared to a $35.9 million gain in the prior-year period), and a $21.9 million decrease in cash payments upon derivative contract settlements;

- Lease operating expenses increased $17.9 million (15%), primarily due to higher power and fuel costs and workover costs; and
- Income tax expense increased by $40.9 million.

Common Share Repurchase Program. In early May 2022, our Board of Directors authorized a common share repurchase program for up to $250 million of outstanding Denbury common stock. During June and July 2022, the Company repurchased 1,615,356 shares of Denbury common stock under this program for approximately $100 million, at an average price of $61.92 per share. In August 2022, the Board increased Denbury's stock repurchase authorization by $100 million, thus a total of $250 million of common stock currently remains authorized for future repurchases under this program. The program has no pre-established ending date and may be suspended or discontinued at any time. The Company is not obligated to repurchase any dollar amount or specific number of shares of its common stock under the program.

Commencement of Cedar Creek Anticline CO_2 Injection. In early February 2022, we commenced CO_2 injection in the first phase of our CCA EOR project. In order to stay ahead of potential supply chain delays, we have increased capital investment in the second half of the year at CCA to accelerate our procurement of compression equipment and construction of CO_2 recycle facilities to ensure facilities are in place to handle anticipated production from the field. We continue to expect tertiary oil production response from CCA in the second half of 2023. In addition, drilling and facility construction at the Company's Pennel CO_2 pilot, in advance of Phase 2 development of CCA, commenced during the third quarter.

Warrant Exercises. In September 2020 we issued 2,631,579 Series A warrants with an exercise price of $32.59 per share and 2,894,740 Series B warrants with an exercise price of $35.41 per share. The warrants may be exercised for cash or on a cashless basis. The Series A warrants are exercisable until September 18, 2025, and the Series B warrants are exercisable until September 18, 2023, at which times the warrants expire. During the three and nine months ended September 30, 2022, 119,367 and 1,941,380 of Series A and B warrants were exercised for a total of 71,440 shares and 1,073,004 shares, respectively, most of which were exercised on a cashless basis. At September 30, 2022, the Company had approximately 3.2 million warrants outstanding, 1.8 million of Series A and 1.4 million of Series B, which represents approximately 58.7% of the aggregate Series A and B warrants issued in September 2020.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our cash flows from operations and availability under our senior secured bank credit facility are our primary sources of capital and liquidity. Our most significant cash capital outlays relate to our oil and gas development capital expenditures and CCUS initiatives. As of September 30, 2022, we had $15.0 million of outstanding borrowings and $11.4 million of outstanding letters of credit under our $750 million senior secured bank credit facility, leaving us with $723.6 million of borrowing base availability and approximately $724.1 million of total liquidity including our cash position at September 30, 2022. This liquidity is more than adequate to meet our currently planned operating and capital needs.

Nine Months Ended September 2022 Sources and Uses of Cash Flow. During the nine months ended September 30, 2022, we generated cash flows from operations of $396.4 million, while utilizing net cash of $288.0 million in investing activities, primarily related to oil and gas and CCUS, and utilizing net cash of $110.6 million in financing activities, $100.0 million of which was utilized for the repurchase of Denbury common stock under the Company's stock repurchase program.

2022 Capital Expenditure Plans. Based on our most recent budget, our full-year 2022 estimate for oil and gas development capital spending, excluding capitalized acquisitions and capitalized interest, is approximately $360 million. In addition to our budgeted oil and natural gas capital investments, we have budgeted approximately $50 million in connection with our strategic CCUS priorities, with expenditures primarily focused on securing CO_2 sequestration sites and drilling one or more stratigraphic test wells in those sequestration sites. Due to supply chain disruptions, the timing of certain of the Company's oil and gas development activities has been delayed from when originally projected to later in the year.

Capital Expenditure Summary. For purposes of tracking and comparing our capital budget to capital expenditure activity, we base those comparisons on when the capital expenditures are incurred, which is generally different than what is reported in our cash flow statements which reflects when cash is actually paid. The information included in the following table reflects incurred capital expenditures for the nine months ended September 30, 2022 and 2021:

In thousands	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Capital expenditure summary[1]		
CCA EOR field expenditures[2]	$ 73,825	$ 19,091
CCA CO_2 pipelines	1,728	59,545
CCA tertiary development	75,553	78,636
Non-CCA tertiary and non-tertiary fields	138,910	71,507
CO_2 sources, other CO_2 pipelines and other	6,124	1,039
Capitalized internal costs[3]	22,640	22,639
Oil and gas development capital expenditures	243,227	173,821
CCUS storage sites and related capital expenditures	32,100	—
Oil and gas and CCUS development capital expenditures	275,327	173,821
Capitalized interest	3,177	3,500
Acquisitions of oil and natural gas properties[4]	874	10,927
Investment in Clean Hydrogen Works	10,000	—
Total capital expenditures	$ 289,378	$ 188,248

(1) Capital expenditures in this summary are presented on an as-incurred basis (including accruals) and are $7.2 million higher than the capital expenditures in the Unaudited Condensed Consolidated Statements of Cash Flows which are presented on a cash basis.
(2) Includes pre-production CO_2 costs associated with the CCA EOR development project totaling $17.9 million during the first nine months of 2022.
(3) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.
(4) Primarily consists of working interest positions in the Wind River Basin enhanced oil recovery fields acquired on March 3, 2021.

Supply Chain Issues and Potential Cost Inflation. Recent worldwide and U.S. supply chain issues, together with rising commodity prices and tight labor markets in the U.S., have increased our costs during late 2021 and thus far in 2022. Based on cost increases and shortages experienced across the industry and higher fuel and power costs thus far in 2022, we anticipate additional increases in the cost of, and demand for, goods and services and wages in our operations during the remainder of 2022 which could negatively impact our results of operations and cash flows in future periods. See *Results of Operations - Production Expenses* below for further discussion.

Senior Secured Bank Credit Agreement. In September 2020, we entered into a $575 million bank credit agreement for a senior secured revolving credit facility with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined semiannually on or around May 1 and November 1 of each year. 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.

On May 4, 2022, we entered into a Second Amendment to the Bank Credit Agreement, which among other things:

- Increased the borrowing base and lender commitments from $575 million to $750 million;
- Extended the maturity date from January 30, 2024 to May 4, 2027;

- Modified the interest provisions on loans under the Bank Credit Agreement to (1) reduce the applicable margin for alternate base rate loans from 2% to 3% per annum to 1.5% to 2.5% per annum and (2) replace provisions referencing LIBOR loans with Secured Overnight Financing Rate loans, with an applicable margin of 2.5% to 3.5% per annum; and
- Permitted us to pay dividends on our common stock and make other unlimited restricted payments and investments so long as (1) no event of default or borrowing base deficiency exists; (2) our total leverage ratio is 1.5 to 1 or lower; and (3) availability under the Bank Credit Agreement is at least 20% of the borrowing base.

As part of our Fall 2022 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $750 million, with our next scheduled redetermination around May 1, 2023.

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 certain exceptions to such limitations, as specified in the Bank Credit Agreement. Our Bank Credit Agreement required certain minimum commodity hedge levels in connection with our emergence from bankruptcy; however, these conditions were met as of December 31, 2020, and we currently have no ongoing hedging requirements under the Bank Credit Agreement.

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.

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 September 30, 2022, our ratio of consolidated total debt to consolidated EBITDAX was 0.03 to 1.0 (with a maximum permitted ratio of 3.5 to 1.0) and our current ratio was 2.68 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 November 2, 2022, and current oil commodity 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 and amendments thereto, each of which is filed as an exhibit to our periodic reports filed with the Securities and Exchange Commission ("SEC"). The Second Amendment to the Credit Agreement, which is attached as Exhibit 10(d) to the Form 10-Q filed on May 6, 2022, contains the full text of the current version of the Bank Credit Agreement inclusive of all changes made by virtue of both the First and Second Amendments thereto.

Commitments, Obligations and Off-Balance Sheet Arrangements. We have numerous contractual commitments in the ordinary course of business including debt service requirements, operating 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 off-balance sheet arrangements include obligations for various development and exploratory expenditures that arise from our normal oil and natural gas or CCUS capital expenditure program or from other transactions common to our industry, none of which are recorded on our balance sheet. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs estimated in our proved reserve reports.

Our commitments, obligations and off-balance sheet arrangements as of December 31, 2021, are detailed 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*.

RESULTS OF OPERATIONS

Certain of our operating results and statistics for the comparative three and nine months ended September 30, 2022 and 2021 are included in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30	
In thousands, except per-share and unit data	2022	2021	2022	2021
Financial results				
Net income (loss)[1]	$ 250,423	$ 82,708	$ 405,045	$ (64,629)
Net income (loss) per common share – basic[1]	4.89	1.62	7.86	(1.27)
Net income (loss) per common share – diluted[1]	4.66	1.51	7.43	(1.27)
Net cash provided by operating activities	156,301	104,019	396,409	247,557
Average daily sales volumes				
Bbls/d	45,639	48,145	45,404	47,276
Mcf/d	8,815	9,222	8,770	8,739
BOE/d[2]	47,109	49,682	46,866	48,732
Oil and natural gas sales				
Oil sales	$ 389,543	$ 305,093	$ 1,217,377	$ 818,714
Natural gas sales	5,680	3,361	14,727	7,893
Total oil and natural gas sales	$ 395,223	$ 308,454	$ 1,232,104	$ 826,607
Commodity derivative contracts[3]				
Payment on settlements of commodity derivatives	$ (55,780)	$ (77,670)	$ (276,796)	$ (179,466)
Noncash fair value gains (losses) on commodity derivatives	165,028	35,925	136,471	(150,686)
Commodity derivatives income (expense)	$ 109,248	$ (41,745)	$ (140,325)	$ (330,152)
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$ 92.77	$ 68.88	$ 98.21	$ 63.44
Natural gas price per Mcf	7.00	3.96	6.15	3.31
Unit prices – including impact of derivative settlements[3]				
Oil price per Bbl	$ 79.49	$ 51.35	$ 75.88	$ 49.53
Natural gas price per Mcf	7.00	3.96	6.15	3.31
Oil and natural gas operating expenses				
Lease operating expenses	$ 134,464	$ 116,536	$ 376,643	$ 308,731
Transportation and marketing expenses	5,191	5,985	14,638	22,304
Production and ad valorem taxes	33,080	23,464	99,093	63,195
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$ 91.19	$ 67.48	$ 96.30	$ 62.13
Lease operating expenses	31.03	25.50	29.44	23.21
Transportation and marketing expenses	1.20	1.31	1.14	1.68
Production and ad valorem taxes	7.63	5.13	7.75	4.75
CO_2 – revenues and expenses				
CO_2 sales and transportation fees	$ 18,586	$ 12,237	$ 44,618	$ 31,599
CO_2 operating and discovery expenses	(2,066)	(1,963)	(6,564)	(4,487)
CO_2 revenue and expenses, net	$ 16,520	$ 10,274	$ 38,054	$ 27,112

(1) Includes a pre-tax full cost pool ceiling test write-down of our oil and natural gas properties of $14.4 million during the first quarter of 2021.

(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 2021 and for the first three quarters of 2022 is shown below:

	Average Daily Sales Volumes (BOE/d)						
Operating Area	Third Quarter 2022	Second Quarter 2022	First Quarter 2022	Fourth Quarter 2021	Third Quarter 2021	Second Quarter 2021	First Quarter 2021
Tertiary oil sales volumes							
Gulf Coast region							
Delhi	2,557	2,478	2,675	2,731	2,859	2,931	2,925
Hastings	4,211	4,304	4,430	4,212	4,343	4,487	4,226
Heidelberg	3,571	3,528	3,653	3,797	3,895	3,942	4,054
Oyster Bayou	3,490	3,423	3,745	4,039	3,942	3,791	3,554
Tinsley	3,133	3,050	3,015	3,353	3,390	3,455	3,424
Other(1)	5,541	5,422	5,498	5,801	5,907	6,074	6,098
Total Gulf Coast region	22,503	22,205	23,016	23,933	24,336	24,680	24,281
Rocky Mountain region							
Bell Creek	3,975	4,122	4,474	4,331	4,330	4,394	4,614
Wind River Basin	3,121	2,703	2,517	2,452	2,581	2,326	691
Other(2)	2,759	2,361	2,229	2,099	2,122	2,052	1,882
Total Rocky Mountain region	9,855	9,186	9,220	8,882	9,033	8,772	7,187
Total tertiary oil sales volumes	32,358	31,391	32,236	32,815	33,369	33,452	31,468
Non-tertiary oil and gas sales volumes							
Gulf Coast region							
Total Gulf Coast region	3,727	3,566	3,630	3,929	3,763	3,415	3,621
Rocky Mountain region							
Cedar Creek Anticline	9,593	10,224	9,721	10,784	11,182	10,918	11,150
Other(3)	1,431	1,380	1,338	1,354	1,368	1,348	1,118
Total Rocky Mountain region	11,024	11,604	11,059	12,138	12,550	12,266	12,268
Total non-tertiary sales volumes	14,751	15,170	14,689	16,067	16,313	15,681	15,889
Total sales volumes	47,109	46,561	46,925	48,882	49,682	49,133	47,357

(1) Includes Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb, Soso, and West Yellow Creek fields.
(2) Includes tertiary sales volumes related to our working interest positions in the Salt Creek and Grieve fields.
(3) Includes non-tertiary sales volumes from Wind River Basin, as well as Hartzog Draw and Bell Creek fields.

Total sales volumes during the third quarter of 2022 averaged 47,109 BOE/d, including 32,358 Bbls/d from tertiary properties and 14,751 BOE/d from non-tertiary properties. This sales volume was relatively flat with second quarter of 2022 sales volumes as sales volume increases at Wind River Basin (437 BOE/d increase) and Grieve fields (410 BOE/d increase) in the Rocky Mountain region were offset by lower production across various fields, most notably at CCA due in part to downtime associated with installation of the new CO_2 flood. On a year-over-year basis, sales volumes decreased 2,573 BOE/d (5%) compared to sales levels in the third quarter of 2021 primarily attributable to low levels of capital investment and development spending in recent years (excluding the new EOR development at CCA). We currently expect sales volumes to increase modestly during the fourth quarter of 2022, as a result of incremental production increases from development projects completed in 2022.

Our sales volumes during the three and nine months ended September 30, 2022 were 97% oil, consistent with our sales during the comparable prior-year periods.

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and nine months ended September 30, 2022 increased 28% and 49%, respectively, compared to these revenues for the same periods in 2021. The changes in our oil and natural gas revenues are due to higher realized commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

	Three Months Ended September 30, 2022 vs. 2021		Nine Months Ended September 30, 2022 vs. 2021	
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	$ (15,975)	(5)%	$ (31,664)	(4)%
Increase in realized commodity prices	102,744	33 %	437,161	53 %
Total increase in oil and natural gas revenues	$ 86,769	28 %	$ 405,497	49 %

Excluding any impact of our commodity derivative contracts, our average net realized commodity prices and NYMEX differentials were as follows during each of the first three quarters and nine months ended September 30, 2022 and 2021:

	Three Months Ended						Nine Months Ended	
	March 31,		June 30,		September 30,		September 30,	
	2022	2021	2022	2021	2022	2021	2022	2021
Average net realized prices								
Oil price per Bbl	$ 93.17	$ 56.28	$ 108.81	$ 64.70	$ 92.77	$ 68.88	$ 98.21	$ 63.44
Natural gas price per Mcf	4.66	3.29	6.76	2.64	7.00	3.96	6.15	3.31
Price per BOE	91.14	55.24	106.67	63.23	91.19	67.48	96.30	62.13
Average NYMEX differentials								
Gulf Coast region								
Oil per Bbl	$ (1.37)	$ (1.37)	$ 0.16	$ (1.13)	$ 0.66	$ (1.77)	$ (0.26)	$ (1.40)
Natural gas per Mcf	0.16	0.68	0.02	(0.11)	0.37	0.16	0.10	0.26
Rocky Mountain region								
Oil per Bbl	$ (1.38)	$ (1.80)	$ 0.01	$ (1.59)	$ 1.02	$ (1.72)	$ (0.08)	$ (1.49)
Natural gas per Mcf	0.08	0.49	(1.12)	(0.47)	(1.59)	(0.65)	(0.86)	(0.22)
Total Company								
Oil per Bbl	$ (1.37)	$ (1.54)	$ 0.09	$ (1.32)	$ 0.82	$ (1.75)	$ (0.18)	$ (1.44)
Natural gas per Mcf	0.11	0.58	(0.71)	(0.33)	(0.90)	(0.33)	(0.51)	(0.02)

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 positive $0.66 per Bbl during the third quarter of 2022, an improvement compared to a negative $1.77 per Bbl during the third quarter of 2021 and a positive $0.16 per Bbl during the second quarter of 2022. During the third quarter of 2022, the Company benefited from improved pricing for its Gulf Coast grades relative to NYMEX WTI prices.

- **Rocky Mountain Region**. Our average NYMEX oil differentials in the Rocky Mountain region was a positive $1.02 per Bbl during the third quarter of 2022, compared to $1.72 per Bbl below NYMEX during the third quarter of 2021 and essentially flat with NYMEX WTI during the second quarter of 2022. Our differentials in the Rocky Mountain region improved as demand for this crude remained robust while also benefiting from being sold under a Cushing related price index.

CO_2 Revenues and Expenses

We sell a portion of the CO_2 we own 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. CO_2 sales and transportation fees were $18.6 million and $44.6 million during the three and nine months ended September 30, 2022, respectively, compared to $12.2 million and $31.6 million during the three and nine-month periods ended September 30, 2021, respectively. The increase in CO_2 sales and transportation fees from the prior-year periods is primarily due to revenues received pursuant to a short-term contractual agreement that we expect to end during the fourth quarter of 2022.

Oil Marketing Revenues and Purchases

In certain situations, we purchase and subsequently sell oil from third parties. We recognize the revenue received and the associated expenses incurred on these sales on a gross basis as "Oil marketing revenues" and "Oil marketing purchases" 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 nine months ended September 30, 2022 and 2021:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2022	2021	2022	2021
Payment on settlements of commodity derivatives	$ (55,780)	$ (77,670)	$ (276,796)	$ (179,466)
Noncash fair value gains (losses) on commodity derivatives	165,028	35,925	136,471	(150,686)
Total income (expense)	$ 109,248	$ (41,745)	$ (140,325)	$ (330,152)

Changes in our commodity derivatives expense are related to the expiration of commodity derivative contracts, changes in oil futures prices between reporting dates, and new commodity derivative contract commitments for future periods. During the first nine months of 2022, we paid $276.8 million upon settlement of commodity derivative contracts, corresponding with the large increase in oil prices and the Company's oil revenues during that same period.

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 2023 using NYMEX fixed-price swaps and costless collars. See Note 7, *Commodity Derivative Contracts*, to the Unaudited Condensed Consolidated Financial Statements for additional details of our outstanding commodity derivative contracts as of September 30, 2022, 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 November 2, 2022:

		4Q 2022	**1H 2023**	**2H 2023**
WTI NYMEX	Volumes Hedged (Bbls/d)	9,500	8,500	9,000
Fixed-Price Swaps	Weighted Average Swap Price	$57.52	$75.84	$77.60
WTI NYMEX	Volumes Hedged (Bbls/d)	11,500	17,500	9,000
Collars	Weighted Average Floor / Ceiling Price	$52.39 / $67.29	$69.71 / $100.42	$68.33 / $100.69
	Total Volumes Hedged (Bbls/d)	21,000	26,000	18,000

Based on current contracts in place and NYMEX oil futures prices as of November 2, 2022, which averaged approximately $89 per Bbl, we currently expect that we would make cash payments of approximately $49 million upon settlement of our October through December 2022 contracts, the amount of which is primarily dependent upon fluctuations in future NYMEX oil prices in relation to the prices of our remaining 2022 fixed-price swaps which have a weighted average NYMEX oil price of $57.52 per Bbl and weighted average ceiling prices of our 2022 collars of $67.29 per Bbl. Changes in commodity prices, expiration of contracts, and new commodity contract commitments cause fluctuations in the estimated fair value of our oil derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period changes in the fair value of these contracts, as outlined above, are recognized in our statements of operations.

Production Expenses

Lease Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data	2022	2021	2022	2021
Total lease operating expenses	$ 134,464	$ 116,536	$ 376,643	$ 308,731
Total lease operating expenses per BOE	$ 31.03	$ 25.50	$ 29.44	$ 23.21

Compared to the prior year third quarter, total lease operating expenses for the third quarter of 2022 increased $17.9 million (15%) on an absolute-dollar basis, or $5.53 (22%) on a per-BOE basis. The increase on an absolute-dollar basis was primarily due to higher power and fuel costs ($9.3 million), higher workover costs ($5.6 million), and higher labor costs ($2.1 million). These cost increases were partially inflation driven and partially activity driven, with higher power costs primarily impacted by higher natural gas prices and higher workover and labor costs impacted by both inflation and higher activity levels. The percentage increase on a per-BOE basis was further impacted by the lower production in the current year period as compared to the prior year period.

When comparing the first nine months of 2022 and 2021, total lease operating expenses increased from the prior year period by $67.9 million (22%) on an absolute-dollar basis, or $6.23 (27%) on a per-BOE basis. The increase on an absolute-dollar basis was primarily due to higher power and fuel costs ($17.7 million), higher workover costs ($13.2 million), higher labor costs ($5.0 million), and higher CO_2 purchase costs ($3.3 million). In addition, the nine-month period comparison was further impacted by (a) a 2021 period benefit of $16.1 million resulting from compensation under the Company's power agreements for power interruption during the severe winter storm in February 2021 which related to power outages in Texas and disrupted the Company's operations and (b) in the 2022 period, an additional $10.6 million of expense reflecting an entire nine months' worth of lease operating expenses from our March 2021 acquisition of Wind River Basin properties. Absent these two factors, lease operating expenses for the nine months ended September 30, 2022 increased 13% on an absolute-dollar basis from the same period in 2021. Consistent with the quarterly comparison cost increases, these increases are related to both inflation and higher activity levels, and the percentage increase on a per-BOE basis was further impacted by lower production in the current year period.

Compared to the second quarter of 2022, lease operating expenses in the most recent quarter increased $10.1 million (8%) on an absolute-dollar basis and $1.68 (6%) on a per-BOE basis, due primarily to higher workover, and power and fuel costs, as well as absence in the third quarter of 2022 of the benefit for an insurance reimbursement totaling $6.7 million for property damage costs incurred during 2013 at Delhi Field.

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 $5.2 million and $6.0 million for the three months ended September 30, 2022 and 2021, respectively, and $14.6 million and $22.3 million for the nine months ended September 30, 2022 and 2021, respectively. The decreases during the most recent comparative three and nine-month periods were primarily due to a change in the sales contracts of certain of our production, which reduced our transportation expense.

Taxes Other Than Income

Taxes other than income includes production, ad valorem and franchise taxes. Taxes other than income increased $9.6 million (40%) and $36.0 million (55%) during the three and nine months ended September 30, 2022, 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")

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data and employees	2022	2021	2022	2021
Cash G&A costs	$ 16,655	$ 12,832	$ 47,507	$ 40,033
Stock-based compensation	4,416	2,556	11,491	22,788
G&A expense	$ 21,071	$ 15,388	$ 58,998	$ 62,821
G&A per BOE				
Cash G&A costs	$ 3.84	$ 2.81	$ 3.71	$ 3.01
Stock-based compensation	1.02	0.56	0.90	1.71
G&A expenses	$ 4.86	$ 3.37	$ 4.61	$ 4.72
Employees as of period end	756	698		

Our G&A expense on an absolute-dollar basis was $21.1 million during the three months ended September 30, 2022, an increase of $5.7 million from the same prior-year period, with the increase primarily due to higher employee-related costs (including $1.9 million for stock-based compensation) and higher professional service fees. During the nine months ended September 30, 2022, our G&A expense decreased $3.8 million, primarily due to a decrease in stock-based compensation as the nine months ended September 30, 2021 included $15.3 million of stock-based compensation expense in the first quarter of 2021 resulting from the accelerated performance achievement and vesting of performance-based equity awards granted in late 2020, partially offset by higher employee-related costs and professional service fees.

Interest and Financing Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data and interest rates	2022	2021	2022	2021
Cash interest[1]	$ 1,422	$ 1,233	$ 3,804	$ 4,902
Noncash interest expense	531	685	2,465	2,055
Less: capitalized interest	(1,044)	(1,249)	(3,177)	(3,500)
Interest expense, net	$ 909	$ 669	$ 3,092	$ 3,457
Interest expense, net per BOE	$ 0.21	$ 0.15	$ 0.24	$ 0.26
Average debt principal outstanding	$ 30,152	$ 55,667	$ 31,158	$ 99,243
Average cash interest rate[2]	6.9 %	8.9 %	6.1 %	6.6 %

(1) Includes commitment fees paid on the Company's bank credit facility but excludes debt issue costs.
(2) Excludes commitment fees paid on the Company's bank credit facility and debt issue costs.

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

In thousands, except per-BOE data	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Oil and natural gas properties	$ 31,188	$ 29,269	$ 88,940	$ 89,834
CO_2 properties, pipelines, plants and other property and equipment	6,492	8,422	19,485	23,688
Total DD&A	$ 37,680	$ 37,691	$ 108,425	$ 113,522
DD&A per BOE				
Oil and natural gas properties	$ 7.20	$ 6.40	$ 6.95	$ 6.75
CO_2 properties, pipelines, plants and other property and equipment	1.49	1.85	1.52	1.78
Total DD&A cost per BOE	$ 8.69	$ 8.25	$ 8.47	$ 8.53
Write-down of oil and natural gas properties	$ —	$ —	$ —	$ 14,377

DD&A expense during the three months ended September 30, 2022, was essentially flat when compared to the same period in 2021, primarily due to higher depletable costs for our oil and gas properties and an increase in accretion expense on our asset retirement obligations, offset by lower depreciation on other fixed assets and CO_2 sources. DD&A expense decreased $5.1 million during the nine months ended September 30, 2022, when compared to the same prior-year period, primarily due to a lower depletion rate as a result of an increase in our estimate of proved reserves between the periods based on higher commodity pricing and lower depreciation on other fixed assets and CO_2 sources.

First Quarter 2021 Full Cost Pool Ceiling Test Write-Down

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period 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. The write-down was primarily a result of the March 2021 acquisition of Wyoming CO_2 EOR properties (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 did not record a ceiling test write-down during the three or nine months ended September 30, 2022.

Other Expenses

Other expenses during the three and nine months ended September 30, 2022 totaled $2.7 million and $11.5 million, respectively. Other expense during the nine months ended September 30, 2022, includes a $3.9 million accrual for a preliminarily assessed civil penalty proposed by the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation in a Notice of Probable Violation (see Item 1, *Legal Proceedings – Notice of Probable Violation from Pipeline and Hazardous Materials Safety Administration ("PHMSA") Regarding Delta-Tinsley CO_2 Pipeline Failure*). Other expenses totaled $4.6 million and $9.9 million during the three and nine months ended September 30, 2021, respectively.

Income Taxes

In thousands, except per-BOE amounts and tax rates	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Current income tax expense (benefit)	$ 4,012	$ 350	$ 6,363	$ (101)
Deferred income tax expense (benefit)	37,309	53	53,301	(34)
Total income tax expense (benefit)	$ 41,321	$ 403	$ 59,664	$ (135)
Average income tax expense (benefit) per BOE	$ 9.54	$ (0.09)	$ 4.67	$ (0.01)
Effective tax rate	14.2 %	0.5 %	12.8 %	0.2 %
Total net deferred tax liability	$ 54,940	$ 1,241		

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 2022 and 2021. Our effective tax rate for the three and nine months ended September 30, 2022 was significantly lower than our estimated statutory rate primarily due to the release of the valuation allowance that was recorded in the three and nine months ended September 30, 2022. Our annualized effective tax rate for the year ended December 31, 2022 is currently estimated to be approximately 15%, as it includes the impact of the release of an additional $11.0 million of valuation allowances during the fourth quarter of 2022. This rate could move higher or lower based on our ultimate level of income.

We make estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Significant judgment is required in estimating valuation allowances, and in making this determination we consider all available positive and negative evidence and make certain assumptions. The realization of a deferred tax asset ultimately depends on the existence of sufficient taxable income in the applicable carryback or carryforward periods. In our assessment, we consider the nature, frequency, and severity of current and cumulative losses, as well as historical and forecasted financial results, the overall business environment, our industry's historic cyclicality, the reversal of existing deferred tax assets and liabilities, and tax planning strategies.

We assess the valuation allowance recorded on our deferred tax assets, which was $125.5 million at December 31, 2021, on a quarterly basis. This valuation allowance on our federal and certain state deferred tax assets was recorded in September 2020 after the application of fresh start accounting, as (1) the tax basis of our assets, primarily our oil and gas properties, was in excess of the carrying value, as adjusted for fresh start accounting and (2) our historical pre-tax income reflected a three-year cumulative loss primarily due to ceiling test write-downs and reorganization items that were recorded in 2020. While we continued to be in a cumulative three-year-loss position during the first quarter of 2022, we initially determined, at that time, that there was sufficient positive evidence, primarily related to a substantial increase in worldwide oil prices, to conclude that $64.9 million of our federal and certain state deferred tax assets are more likely than not to be realized. Accordingly, we reversed $5.9 million, $18.8 million, and $29.2 million of this valuation allowance during the three months ended March 31, June 30, and September 30, 2022, respectively, and currently expect to reverse the remaining $11.0 million in December 31, 2022, resulting in a reduction to our annualized effective tax rate. We will continue to maintain a valuation allowance of $60.6 million for certain state tax benefits that we currently do not expect to realize before their expiration.

As of September 30, 2022, we had $0.6 million of alternative minimum tax credits, which under the Tax Cut and Jobs Act will be refundable by 2022 and are recorded as a receivable on the balance sheet. Our significant 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 September 30,		Nine Months Ended September 30,	
Per-BOE data	2022	2021	2022	2021
Oil and natural gas revenues	$ 91.19	$ 67.48	$ 96.30	$ 62.13
Payment on settlements of commodity derivatives	(12.87)	(16.99)	(21.63)	(13.49)
Lease operating expenses	(31.03)	(25.50)	(29.44)	(23.21)
Production and ad valorem taxes	(7.63)	(5.13)	(7.75)	(4.75)
Transportation and marketing expenses	(1.20)	(1.31)	(1.14)	(1.68)
Production netback	38.46	18.55	36.34	19.00
CO_2 sales, net of operating and discovery expenses	3.81	2.25	2.98	2.04
General and administrative expenses[(1)]	(4.86)	(3.37)	(4.61)	(4.72)
Interest expense, net	(0.21)	(0.15)	(0.24)	(0.26)
Stock compensation and other	(1.25)	(0.31)	(0.74)	1.18
Changes in assets and liabilities relating to operations	0.11	5.79	(2.75)	1.37
Cash flows from operations	36.06	22.76	30.98	18.61
DD&A	(8.69)	(8.25)	(8.47)	(8.53)
Write-down of oil and natural gas properties	—	—	—	(1.08)
Deferred income taxes	(8.61)	(0.01)	(4.17)	—
Noncash fair value gains (losses) on commodity derivatives	38.08	7.86	10.66	(11.33)
Other noncash items	0.94	(4.26)	2.66	(2.53)
Net income (loss)	$ 57.78	$ 18.10	$ 31.66	$ (4.86)

(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 nine months ended September 30, 2021, resulting in a significant non-recurring expense, which if excluded, would have caused these expenses to average $3.58 per BOE.

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, such as those related to our CCUS storage sites and related assets, 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, cash flows, production and capital expenditures, and other plans and objectives for the future operations of Denbury, projections or assumptions as to oil markets or general economic conditions and the economics of a carbon capture, use and storage industry ("CCUS"), 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 recent higher worldwide oil prices; the extent of future oil price volatility; current or future liquidity sources or their adequacy to support our anticipated future activities; statements or predictions related to the ultimate timing and financial impact of our current or proposed carbon capture, use and storage arrangements; our projected production levels, oil and natural gas revenues, oil and gas prices and oilfield costs, the impact of current supply chain and inflation on our results of operations; current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows; availability, terms and financial statement and cash settlement impact of commodity derivative contracts or their predicted downside cash flow protection; forecasted drilling activity or methods, including the timing and location thereof; estimated timing of commencement of CO_2 injections in particular fields or areas, or initial production responses in tertiary flooding projects; other development activities, finding costs, interpretation or prediction of formation details, 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 changes or proposed changes in Federal or state tax or environmental laws or regulations; the outcomes of any pending litigation or regulatory proceedings; and overall worldwide or U.S. 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 that could significantly and adversely affect current plans, anticipated outcomes, 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 or U.S. oil prices, especially in light of existing geopolitical and economic events, such as the war in Ukraine and ensuing energy supply uncertainties in Western Europe; decisions as to production levels and/or pricing by OPEC or U.S. producers in future periods; the impact of COVID-19 or other viral outbreaks on economic activity levels and ultimately oil prices; the pace and terms of agreements reached with third parties for the capture, transportation, use and ultimate permanent sequestration of CO_2; the timing and success of CCUS projects that, while undertaken by third parties, are related to our CCUS efforts; success of our risk management techniques; 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, climate events such as hurricanes, tropical storms, floods, forest fires, or other natural occurrences; conditions in the worldwide financial, trade currency and credit markets; the risks and uncertainties inherent in oil and gas drilling and production activities; and the risks and uncertainties set forth from time to time in this or 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

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, expectation of future commodity prices, and occasionally requirements under our bank credit facility. As of September 30, 2022, we do not have any hedging requirements under our Bank Credit Agreement. 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 2023 using NYMEX fixed-price swaps and costless collars. Depending on market conditions, we may continue to add to our existing 2022 and 2023 hedges. See also Note 6, *Income Taxes*, and Note 8*, 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 September 30, 2022, the fair value of our commodity derivative contracts was a net asset of $2.0 million, a $165.1 million increase from the $163.1 million net liability recorded at June 30, 2022 and a $136.5 million increase from the $134.5 million net liability recorded at December 31, 2021. The changes are primarily related to the expiration of commodity derivative contracts during the three and nine months ended September 30, 2022, changes in oil futures prices between December 31, 2021 and September 30, 2022, and new commodity derivative contract commitments during 2022 for future periods.

Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil futures prices and derivative contracts in place as of September 30, 2022, and assuming both a 10% increase and decrease thereon, we would expect to make payments on our crude oil derivative contracts as shown in the following table:

In thousands		Receipt / (Payment)
Based on:		
Futures prices as of September 30, 2022	$	(17,475)
10% increase in prices		(53,553)
10% decrease in prices		28,694

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.

Debt and Interest Rate Sensitivity

As of September 30, 2022, we had $15.0 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 not 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 September 30, 2022:

In thousands	2022 - 2026	2027	Total	Fair Value
Variable rate debt:				
Senior Secured Bank Credit Facility (weighted average interest rate of 7.75% at September 30, 2022)	$ —	$ 15,000	$ 15,000	$ 15,000

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

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 September 30, 2022, 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 third quarter of fiscal 2022, 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

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation and regulatory proceedings are 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.

Notice of Probable Violation from Pipeline and Hazardous Materials Safety Administration ("PHMSA") Regarding Delta-Tinsley CO_2 Pipeline Failure

On May 26, 2022, the PHMSA of the U.S. Department of Transportation issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order ("NOPV") relating to the February 2020 pipeline failure near Satartia, Mississippi in our CO_2 pipeline running between the Tinsley and Delhi fields. The NOPV proposed a preliminarily assessed civil penalty of $3.9 million in connection with the incident, which we accrued during the second quarter of 2022. We have responded to the NOPV and are pursuing discussions with PHMSA regarding the probable violations alleged in the NOPV, the proposed civil penalty, and the nature of the compliance order contained in the NOPV.

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, 2021. 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, 2021.

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

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the third quarter of 2022:

Month	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under Plans or Programs [2]
July 2022	1,157,842	$ 61.56	1,157,807	$ 150,000,000
August 2022	—	—	—	$ 250,000,000
September 2022	—	—	—	$ 250,000,000
Total	1,157,842		1,157,807	

(1) Includes 35 shares repurchased in connection with the surrender of shares by our employees to satisfy their tax withholding requirements related to share-based awards that vested during the period.

(2) In early May 2022, our Board of Directors approved a common share repurchase program authorizing the repurchase of up to an aggregate $250 million of Denbury common shares. During June and July 2022, we purchased a total of 1,615,356 shares of Denbury common stock for $100 million under the program. In August 2022, our Board of Directors increased the common share repurchase program by $100 million, leaving $250 million authorized for future repurchases under the program. We are not obligated to repurchase any dollar amount or specified number of shares of our common stock under the program. The stock repurchase program has no pre-established ending date and may be modified, suspended, or discontinued at any time by the board of directors. See further discussion of this program under *Overview – Common Share Repurchase Program*.

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 September 30, 2022, 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.
November 3, 2022	/s/ Mark C. Allen
	Mark C. Allen Executive Vice President and Chief Financial Officer
November 3, 2022	/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.

November 3, 2022

/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.

November 3, 2022

/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 September 30, 2022 (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: November 3, 2022	/s/ Chris Kendall
	Chris Kendall
	President and Chief Executive Officer

Dated: November 3, 2022	/s/ Mark C. Allen
	Mark C. Allen
	Executive Vice President, Chief Financial Officer, Treasurer, and Assistant Secretary