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

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2021

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________ to ____________

Commission file number 001-37907

EXTRACTION OIL & GAS, INC.
(Exact name of registrant as specified in its charter)

Delaware	**46-1473923**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
370 17th Street **Suite 5200** **Denver, Colorado**	**80202**
(Address of principal executive offices)	(Zip Code)

(720) 557-8300

(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of exchange on which registered
Common Stock, par value $0.01	**XOG**	**NASDAQ Global Select Market**

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 pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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 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.

Large Accelerated Filer	☐	Accelerated Filer	☐
Non-Accelerated Filer	☒	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 has filed all documents and reports required to be filed by Sections 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 total number of shares of common stock, par value $0.01 per share, outstanding as of August 6, 2021 was 25,840,663.

EXTRACTION OIL & GAS, INC.
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ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)
(Unaudited)

	Successor	Predecessor
	June 30, 2021	December 31, 2020
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 34,427	$ 205,890
Accounts receivable, net		
Trade	25,649	13,266
Oil, natural gas and NGL sales	74,786	63,429
Inventory, prepaid expenses and other	20,249	36,382
Commodity derivative asset	—	6,971
Total Current Assets	155,111	325,938
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	1,016,374	4,743,463
Unproved oil and gas properties	132,386	220,380
Wells in progress	2,129	129,058
Less: accumulated depletion, depreciation, amortization and impairment charges	(89,876)	(3,459,689)
Net oil and gas properties	1,061,013	1,633,212
Other property and equipment, net of accumulated depreciation and impairment charges	55,565	56,701
Net Property and Equipment	1,116,578	1,689,913
Non-Current Assets:		
Other non-current assets	15,139	9,348
Total Non-Current Assets	15,139	9,348
Total Assets	$ 1,286,828	$ 2,025,199
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 97,470	$ 80,082
Revenue payable	134,948	49,376
Production taxes payable	59,454	2,595
Commodity derivative liability	78,915	2,147
Accrued interest payable	795	692
Asset retirement obligations	13,976	—
DIP Credit Facility—Note 4	—	106,727
Prior Credit Facility—Note 4	—	453,747
Current tax liability	2,100	—
Total Current Liabilities	387,658	695,366
Non-Current Liabilities:		
RBL Credit Facility—Note 4	90,000	—
Production taxes payable	50,945	33,627
Commodity derivative liability	3,302	—
Other non-current liabilities	14,677	—
Asset retirement obligations	74,738	—
Total Non-Current Liabilities	233,662	33,627
Liabilities Subject to Compromise	—	2,143,497
Total Liabilities	621,320	2,872,490
Commitments and Contingencies—Note 12		
Series A Convertible Preferred Stock, $0.01 par value; 50,000,000 shares authorized, 185,280 issued and outstanding as of December 31, 2020	—	191,754
Stockholders' Equity (Deficit):		
Predecessor common stock, $0.01 par value; 900,000,000 shares authorized; 136,588,900 issued and outstanding as of December 31, 2020	—	1,336
Successor common stock, $0.01 par value; 900,000,000 shares authorized; 25,836,944 issued and outstanding as of June 30, 2021	258	—
Predecessor treasury stock, at cost, 38,859,078 shares as of December 31, 2020	—	(170,138)
Additional paid-in capital	552,152	2,140,499
Retained earnings (accumulated deficit)	113,098	(3,010,742)
Total Stockholders' Equity (Deficit)	665,508	(1,039,045)
Total Liabilities and Stockholders' Equity	$ 1,286,828	$ 2,025,199

The accompanying notes are an integral part of these condensed consolidated financial statements.

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)
(Unaudited)

	Successor	Predecessor
	For the Three Months Ended June 30,	For the Three Months Ended June 30,
	2021	2020
Revenues:		
Oil sales	$ 139,110	$ 36,290
Natural gas sales	39,469	16,019
NGL sales	45,048	10,820
Total Revenues	223,627	63,129
Operating Expenses:		
Lease operating expense	13,736	22,984
Transportation and gathering	21,554	26,306
Production taxes	10,911	4,679
Exploration and abandonment expenses	3,586	62,661
Depletion, depreciation, amortization and accretion	50,090	82,620
Impairment of long-lived assets	170	960
General and administrative expense	10,918	25,148
Other operating expenses	5,380	13,209
Total Operating Expenses	116,345	238,567
Operating Income (Loss)	107,282	(175,438)
Other Income (Expense):		
Commodity derivative loss	(75,839)	(69,301)
Reorganization items, net	—	(26,919)
Interest expense	(2,170)	(20,314)
Other income	46	38
Total Other Income (Expense)	(77,963)	(116,496)
Income (Loss) Before Income Taxes	29,319	(291,934)
Income tax expense	(4,775)	—
Net Income (Loss)	$ 24,544	$ (291,934)
Net income attributable to noncontrolling interest	—	—
Net Income (Loss) Attributable to Extraction Oil & Gas, Inc.	24,544	(291,934)
Adjustments to reflect Series A Preferred Stock dividends and accretion of discount	—	(5,818)
Net Income (Loss) Available to Common Shareholders, Basic and Diluted	$ 24,544	$ (297,752)
Income (Loss) Per Common Share—Note 11		
Basic	$ 0.95	$ (2.16)
Diluted	$ 0.93	$ (2.16)
Weighted Average Common Shares Outstanding		
Basic	25,777	138,163
Diluted	26,429	138,163

The accompanying notes are an integral part of these condensed consolidated financial statements.

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)
(Unaudited)

	Successor	Predecessor	
	For the Period from January 21 through June 30,	For the Period from January 1 through January 20,	For the Six Months Ended June 30,
	2021	2021	2020
Revenues:			
Oil sales	$ 239,657	$ 27,137	$ 160,509
Natural gas sales	156,804	7,806	38,321
NGL sales	76,607	8,099	28,013
Gathering and compression	—	—	1,473
Total Revenues	473,068	43,042	228,316
Operating Expenses:			
Lease operating expense	24,391	2,555	53,374
Transportation and gathering	44,742	6,256	49,092
Production taxes	32,351	3,294	18,133
Exploration and abandonment expenses	4,345	316	175,141
Depletion, depreciation, amortization and accretion	88,665	16,133	158,670
Impairment of long-lived assets	170	—	1,736
General and administrative expense	18,458	2,211	35,744
Other operating expenses	9,262	1,107	69,719
Total Operating Expenses	222,384	31,872	561,609
Operating Income (Loss)	250,684	11,170	(333,293)
Other Income (Expense):			
Commodity derivative gain (loss)	(104,325)	(12,586)	193,714
Loss on deconsolidation of Elevation Midstream, LLC	—	—	(73,139)
Reorganization items, net	—	873,908	(26,919)
Interest expense[(1)]	(5,203)	(1,534)	(41,672)
Other income	42	12	612
Total Other Income (Expense)	(109,486)	859,800	52,596
Income (Loss) Before Income Taxes	141,198	870,970	(280,697)
Income tax expense	(28,100)	—	(2,200)
Net Income (Loss)	$ 113,098	$ 870,970	$ (282,897)
Net income attributable to noncontrolling interest	—	—	6,160
Net Income (Loss) Attributable to Extraction Oil & Gas, Inc.	113,098	870,970	(289,057)
Adjustments to reflect Series A Preferred Stock dividends and accretion of discount	—	(418)	(12,336)
Net Income (Loss) Available to Common Shareholders, Basic and Diluted	$ 113,098	$ 870,552	$ (301,393)
Income (Loss) Per Common Share—Note 11			
Basic	$ 4.41	$ 6.37	$ (2.18)
Diluted	$ 4.31	$ 6.37	$ (2.18)
Weighted Average Common Shares Outstanding			
Basic	25,655	136,589	137,945
Diluted	26,262	136,589	137,945

(1) Absent the automatic stay described in *Note 8—Long-Term Debt* to the Company's consolidated financial statements in its Annual Report on Form 10-K for the year ended December 31, 2020, interest expense for the Predecessor period January 1, 2021 to January 20, 2021 would have included an additional $3.7 million related to 2024 and 2026 Senior Notes.

The accompanying notes are an integral part of these condensed consolidated financial statements.

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Successor	Predecessor	
	For the Period from January 21 through June 30,	For the Period from January 1 through January 20,	For the Six Months Ended June 30,
	2021	2021	2020
Cash flows from operating activities:			
Net income (loss)	$ 113,098	$ 870,970	$ (282,897)
Reconciliation of net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	88,665	16,133	158,670
Abandonment and impairment of unproved properties	2,441	—	169,559
Impairment of long-lived assets	170	—	1,736
Amortization of debt issuance costs	909	113	3,190
Non-cash lease expense	2,073	264	8,986
Non-cash reorganization items, net	—	(902,653)	13,270
Non-cash discount on rights offering	1,792	—	—
Contract asset	—	—	12,317
Commodity derivatives loss (gain)	104,325	12,586	(193,714)
Settlements on commodity derivatives	(21,168)	542	65,447
Earnings in unconsolidated subsidiaries	—	—	(480)
Loss on deconsolidation of Elevation Midstream, LLC	—	—	73,139
Deferred income tax expense	—	—	2,200
Stock-based compensation	4,945	302	2,560
Changes in current assets and liabilities:			
Accounts receivable—trade	(10,455)	(598)	(16,998)
Accounts receivable—oil, natural gas and NGL sales	(10,088)	(1,269)	56,828
Inventory, prepaid expenses and other	15,164	(778)	(12,289)
Accounts payable and accrued liabilities	(71,405)	16,192	64,981
Revenue payable	7,195	18,529	(18,924)
Production taxes payable	(86,261)	(13,750)	(23,019)
Accrued interest payable	795	(692)	15,565
Current tax liability	2,100	—	—
Asset retirement expenditures	(2,526)	(545)	(16,173)
Net cash provided by operating activities	141,769	15,346	83,954
Cash flows from investing activities:			
Oil and gas property additions	(55,098)	(9,120)	(193,334)
Acquired oil and gas properties	(5,491)	—	—
Sale of property and equipment	20,253	—	11,147
Gathering systems and facilities additions, net of cost reimbursements	—	—	4,193
Other property and equipment additions	(837)	—	(3,386)
Investment in unconsolidated subsidiaries	—	—	(10,033)
Net cash used in investing activities	(41,173)	(9,120)	(191,413)
Cash flows from financing activities:			
Borrowings under Prior Credit Facility—Note 4	—	—	200,500
Repayments under Prior Credit Facility—Note 4	—	(453,872)	(70,000)
Borrowings under DIP Credit Facility—Note 4	—	—	15,000
Repayments under DIP Credit Facility—Note 4	—	(106,727)	—
Borrowings under RBL Credit Facility—Note 4	60,000	265,000	—
Repayments under RBL Credit Facility—Note 4	(243,746)	—	—
Proceeds from issuance of common stock	7,000	200,473	—
Payment of employee payroll withholding taxes	—	—	(120)
Debt issuance costs and other financing fees	(85)	(6,328)	(22)
Net cash provided by (used in) financing activities	(176,831)	(101,454)	145,358
Effect of deconsolidation of Elevation Midstream, LLC	—	—	(7,728)
Increase (decrease) in cash and cash equivalents	(76,235)	(95,228)	30,171
Cash, cash equivalents and restricted cash at beginning of period	110,662	205,890	32,382
Cash, cash equivalents and restricted cash at end of period	$ 34,427	$ 110,662	$ 62,553
Supplemental cash flow information:			
Property and equipment included in accounts payable and accrued liabilities	$ 32,736	$ 16,320	$ 64,751
Cash paid for income taxes	26,000	—	—
Cash paid for interest	3,600	2,245	26,955
Cash paid for reorganization items, net	45,600	6,545	3,787
Accretion of beneficial conversion feature of Series A Preferred Stock	—	418	3,587
Preferred Units commitment fees and dividends paid-in-kind	—	—	6,160
Series A Preferred Stock dividends paid-in-kind	—	—	8,749
Derivative unwinds reducing the Prior Credit Facility	—	—	96,065
Draw on letter of credit increasing the RBL Credit Facility	8,746	—	—
Draw on letter of credit increasing the Prior Credit Facility	—	125	—
General unsecured claims within accounts payable and accrued liabilities settled with common stock	13,818	—	—
Backstop Commitment Agreement premium within accounts payable and accrued liabilities settled with common stock	—	23,866	—

The accompanying notes are an integral part of these condensed consolidated financial statements.

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND NONCONTROLLING INTEREST
(In thousands)
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Extraction Oil & Gas, Inc. Stockholders' Equity (Deficit)	Noncontrolling Interest	Total Stockholders' Equity (Deficit)
	Shares	Amount	Shares	Amount				Amount	
Balance at January 1, 2021 (Predecessor)	175,448	$ 1,336	38,859	$ (170,138)	$ 2,140,499	$ (3,010,742)	$ (1,039,045)	$ —	$ (1,039,045)
Stock-based compensation	—	—	—	—	302	—	302	—	302
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(418)	—	(418)	—	(418)
Net income	—	—	—	—	—	870,970	870,970	—	870,970
Cancellation of Predecessor equity	(175,448)	(1,336)	(38,859)	170,138	(2,140,383)	2,139,772	168,191	—	168,191
Issuance of Successor equity	24,729	247	—	—	504,205	—	504,452	—	504,452
Issuance of Successor warrants	—	—	—	—	20,403	—	20,403	—	20,403
Balance at January 20, 2021 (Predecessor)	24,729	$ 247	—	$ —	$ 524,608	$ —	$ 524,855	$ —	$ 524,855
Balance at January 21, 2021 (Successor)	24,729	$ 247	—	$ —	$ 524,608	$ —	$ 524,855	$ —	$ 524,855
Stock-based compensation	—	—	—	—	2,174	—	2,174	—	2,174
Net income	—	—	—	—	—	88,554	88,554	—	88,554
Issuance of Successor equity for general unsecured claims	543	5	—	—	11,083	—	11,088	—	11,088
Issuance of Successor equity for rights offering	431	5	—	—	8,787	—	8,792	—	8,792
Balance at March 31, 2021 (Successor)	25,703	$ 257	—	$ —	$ 546,652	$ 88,554	$ 635,463	$ —	$ 635,463
Stock-based compensation	—	—	—	—	2,771	—	2,771	—	2,771
Net income	—	—	—	—	—	24,544	24,544	—	24,544
Issuance of Successor equity for general unsecured claims	134	1	—	—	2,729	—	2,730	—	2,730
Balance at June 30, 2021 (Successor)	25,837	$ 258	—	$ —	$ 552,152	$ 113,098	$ 665,508	$ —	$ 665,508
Balance at January 1, 2020 (Predecessor)	176,517	$ 1,336	38,859	$ (170,138)	$ 2,156,383	$ (1,743,208)	$ 244,373	$ 264,364	$ 508,737
Preferred Units commitment fees & dividends paid-in-kind	—	—	—	—	(6,160)	—	(6,160)	6,160	—
Series A Preferred Stock dividends	—	—	—	—	(4,748)	—	(4,748)	—	(4,748)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,770)	—	(1,770)	—	(1,770)
Restricted stock issued, net of tax withholdings and other	234	—	—	—	(35)	—	(35)	—	(35)
Net income	—	—	—	—	—	9,037	9,037	—	9,037
Effects of deconsolidation of Elevation Midstream, LLC	—	—	—	—	—	—	—	(270,524)	(270,524)
Balance at March 31, 2020 (Predecessor)	176,751	$ 1,336	38,859	$ (170,138)	$ 2,143,670	$ (1,734,171)	$ 240,697	$ —	$ 240,697
Stock-based compensation	—	—	—	—	2,560	—	2,560	—	2,560
Series A Preferred Stock dividends	—	—	—	—	(4,001)	—	(4,001)	—	(4,001)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,817)	—	(1,817)	—	(1,817)
Restricted stock issued, net of tax withholdings and other	452	—	—	—	(85)	—	(85)	—	(85)
Net loss	—	—	—	—	—	(291,934)	(291,934)	—	(291,934)
Balance at June 30, 2020 (Predecessor)	177,203	$ 1,336	38,859	$ (170,138)	$ 2,140,327	$ (2,026,105)	$ (54,580)	$ —	$ (54,580)

The accompanying notes are an integral part of these condensed consolidated financial statements.

EXTRACTION OIL & GAS, INC.
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Business and Organization

Extraction Oil & Gas, Inc. (the “Company” or “Extraction” is an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and natural gas liquids (“NGLs”) reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the “DJ Basin”) of Colorado. As described below in the section titled “*Voluntary Reorganization under Chapter 11 of the Bankruptcy Code*,” during the second quarter of 2020, the Company filed for bankruptcy and, as a result, was delisted from the NASDAQ Global Select Market on June 25, 2020 and began trading on the Pink Open Market under the symbol “XOGAQ.” Also described below, on January 20, 2021 the Company emerged from bankruptcy as a reorganized entity and, as a result, was relisted on the NASDAQ Global Select Market on January 21, 2021 and began trading under the symbol “XOG.”

To facilitate our financial statement presentations, the Company refers to the post-emergence reorganized company in these condensed consolidated financial statements and footnotes as the “Successor Company” for periods subsequent to January 20, 2021 and to the pre-emergence company as the “Predecessor Company” for periods on or prior to January 20, 2021. This delineation between Predecessor Company periods and Successor Company periods is shown in the condensed consolidated financial statements, certain tables within the footnotes to the condensed consolidated financial statements and other parts of this Quarterly Report on Form 10-Q (“Quarterly Report”) through the use of a black line, calling out the lack of comparability between periods.

Bonanza Creek Energy, Inc. Merger and Crestone Peak Merger

As previously disclosed, on May 9, 2021, Bonanza Creek Energy, Inc. (“Bonanza Creek”) and Extraction signed a merger agreement (the “BCEI Merger Agreement”) for an all-stock merger of equals (the “BCEI Merger”). On June 6, 2021, Extraction entered into a merger agreement, by and among Bonanza Creek, Raptor Condor Merger Sub 1, Inc., a Delaware corporation and a wholly owned subsidiary of BCEI, Raptor Condor Merger Sub 2, LLC, a Delaware limited liability company and a wholly owned subsidiary of BCEI, Crestone Peak Resources LP, a Delaware limited partnership, CPPIB Crestone Peak Resources America Inc., a Delaware corporation (“Crestone Peak”), Crestone Peak Resources Management LP, a Delaware limited partnership (the “Crestone Peak Merger Agreement”). The Crestone Peak Merger Agreement, among other things, provides for Bonanza Creek’s acquisition of Crestone Peak (the “Crestone Peak Merger”). The closing of the Crestone Peak Merger is expressly conditioned on the closing of the BCEI Merger. Upon completion of the BCEI Merger and Crestone Peak Merger, the combined company will be named Civitas Resources, Inc. (“Civitas”). Following the BCEI Merger and Crestone Peak Merger, Bonanza Creek President and Chief Executive Officer, Eric Greager, will serve as President and CEO of Civitas. Other senior leadership positions will be filled by current executives of Bonanza Creek and Extraction. As designated in the BCEI Merger agreement, of the six named officers, three will be from Bonanza Creek and three from Extraction. Extraction Chairman of the Board of Directors (“Board”), Ben Dell, will serve as Chairman of Civitas, and Bonanza Creek and Extraction will each nominate four directors, and CPP Investments will nominate one director to Civitas’ diverse, nine-member Board. The Company anticipates the BCEI Merger will be completed during the latter half of 2021.

Voluntary Reorganization under Chapter 11 of the Bankruptcy Code

As previously disclosed, on June 14, 2020 (the “Petition Date”), Extraction and its wholly owned subsidiaries (collectively, the “Debtors”), filed voluntary petitions for relief under chapter 11 (“Chapter 11”) of title 11 of the United States Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the District of Delaware (the “Bankruptcy Court”). The Debtors’ Chapter 11 cases (the “Chapter 11 Cases”) were jointly administered under the caption In *re Extraction Oil & Gas., et al.* Case No. 20-11548 (CSS).

On July 30, 2020, the Debtors filed a proposed Plan of Reorganization (as amended, modified, or supplemented from time to time, the “Plan”) and related Disclosure Statement (as amended or modified, the “Disclosure Statement”) describing the Plan and the solicitation of votes to approve the same from certain of the Debtors’ creditors with respect to the Chapter 11 Cases. Subsequently on October 22, 2020 and November 5, 2020, the Debtors filed first and second amendments, respectively, to the Disclosure Statement. The hearing to consider approval of the Disclosure Statement was held on November 6, 2020. On November 6, 2020, the Bankruptcy Court approved the adequacy of the Disclosure Statement and the Debtors commenced a solicitation process to obtain votes on the Plan. The Plan was confirmed by order of the Bankruptcy Court on December 23, 2020 (the “Confirmation Order”). On January 20, 2021 (the “Emergence Date”), the Plan became effective in accordance with its terms and the Company emerged from the Chapter 11 Cases.

Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements

Basis of Presentation

The unaudited condensed consolidated financial statements include the accounts of the Company, including its wholly owned subsidiaries. Intercompany balances and transactions have been eliminated in consolidation. The financial statements included herein were prepared from the records of the Company in accordance with accounting principles generally accepted in the United States of America (“GAAP”) and the Securities and Exchange Commission rules and regulations for interim financial reporting. In the opinion of management, all adjustments, consisting primarily of normal recurring adjustments that are considered necessary for a fair statement of the unaudited condensed consolidated financial information, have been included. However, operating results for the period presented are not necessarily indicative of the results that may be expected for a full year. Interim condensed consolidated financial statements and the year-end balance sheets do not include all of the information and notes required by GAAP for audited annual consolidated financial statements. These unaudited condensed consolidated financial statements should be read in conjunction with the Company’s audited consolidated financial statements and notes included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2020 (“Annual Report”).

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in *Note 2—Basis of Presentation and Significant Accounting Policies* to the Company’s consolidated financial statements in its Annual Report and are supplemented by the notes to the unaudited condensed consolidated financial statements in this Quarterly Report. As discussed in *Note 3—Fresh Start Reporting*, upon emergence from bankruptcy on January 20, 2021, the Company recorded its consolidated balance sheet accounts at fair value.

The Predecessor Company applied Accounting Standards Codification (“ASC”) *Topic 852—Reorganizations* (“ASC 852”) in preparing the condensed consolidated financial statements. ASC 852 did not apply to the Successor Company. ASC 852 requires the financial statements, for periods subsequent to the Chapter 11 Cases’ filing date, to distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain expenses incurred during the bankruptcy proceedings, including gain on settlement of debt and fresh-start valuations, are recorded as reorganization items, net. In addition, for periods after the Petition Date and through the Emergence Date, Predecessor Company pre-petition obligations that may have been impacted by the Chapter 11 process have been classified on the condensed consolidated balance sheets as “Liabilities Subject to Compromise.” These liabilities are reported at the amounts the Predecessor Company anticipated would be allowed by the Bankruptcy Court as of that balance sheet date, even if they may be settled for lesser amounts. See below for more information regarding reorganization items, net.

GAAP requires certain additional reporting for financial statements prepared between the Petition Date and the Emergence Date, including:

- Reclassification of pre-petition liabilities that are unsecured, under-secured or where it cannot be determined that the liabilities are fully secured to a separate line item in the condensed consolidated balance sheets called “Liabilities Subject to Compromise”; and

- Segregation of reorganization items, net as a separate line in the condensed consolidated statements of operations outside of income from continuing operations.

Accounting policies for the balance sheet accounts listed below are disclosed in the Company’s Annual Report. As of the Effective Date, the amounts for these accounts have been recorded at fair value. After the effective date, the Company will continue to follow the accounting policies within its Annual Report.

- Cash and Cash Equivalents
- Accounts Receivable
- Inventory, Prepaid Expenses and Other
- Oil and Gas Properties
- Other Property and Equipment
- Debt Issuance Costs
- Commodity Derivative Instruments
- Intangible Assets
- Asset Retirement Obligations

Executory Contracts

Subject to certain exceptions, under the Bankruptcy Code, the Debtors may assume, assign, or reject certain executory contracts and unexpired leases subject to the approval of the Bankruptcy Court and certain other conditions. Generally, the rejection of an executory contract or unexpired lease is treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves the Debtors from performing their future obligations under such executory contract or unexpired lease but entitles the contract counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Generally, the assumption of an executory contract or unexpired lease requires the Debtors to cure existing monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance.

Bankruptcy Claims

The Debtors have filed with the Bankruptcy Court schedules and statements setting forth, among other things, the assets and liabilities of each of the Debtors, subject to the assumptions filed in connection therewith. These schedules and statements may be subject to further amendment or modification after filing. Certain holders of pre-petition claims that are not governmental units were required to file proofs of claim by the bar date of August 14, 2020. As of August 3, 2021, the Debtors' have received approximately 2,600 proofs of claim, primarily representing general unsecured claims, for an amount of approximately $5.8 billion. The Bankruptcy Court does not allow for claims that have been acknowledged as duplicates. Approximately 2,200 claims totaling approximately $4.2 billion have been withdrawn, disallowed or are pending approval to be disallowed. As of August 3, 2021, there are a total of approximately $75.1 million in remaining asserted claims in the bankruptcy. For the remaining claims, the Company is attempting to reach settlement with the claimants or has or is expected to object to the claims. Differences in amounts recorded and claims filed by creditors are currently being investigated and resolved, including through filing objections with the Bankruptcy Court, where appropriate. The Company may ask the Bankruptcy Court to disallow claims that the Company believes are duplicative, have been later amended or superseded, are without merit, are overstated or should be disallowed for other reasons. In light of the substantial number of claims filed, the claims resolution process may take considerable time to complete and is continuing even after the Debtors emerged from bankruptcy.

Divestitures

In April 2021, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $15.2 million, subject to customary purchase price adjustments. No gain or loss was recognized. In conjunction with the April 2021 divestiture, the Company recorded a receivable of approximately $2.7 million in the condensed consolidated balance sheet as of June 30, 2021 for post-closing adjustments. The Company continues to explore divestitures as part of our ongoing initiative to divest non-strategic assets.

Segments

The Company has a single reportable segment.

Recent Accounting Pronouncements

In May 2021, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2021-04, Earnings Per Share (Topic 260), Debt—Modifications and Extinguishments (Subtopic 470-50), Compensation—Stock Compensation (Topic 718), and Derivatives and Hedging—Contracts in Entity's Own Equity (Subtopic 815-40). This ASU clarifies accounting for modifications or exchanges of freestanding equity-classified written call options (for example, warrants) that remain equity classified after modification or exchange. The amendments in this ASU are effective for the Company beginning January 1, 2022. Early adoption is permitted and amendments should be applied prospectively to modifications or exchanges occurring on the effective date of the amendments. The Company is evaluating the effect of adopting this guidance.

Other than as disclosed in the Company's Annual Report, there are no other accounting standards applicable to the Company as of June 30, 2021 and through the date of this filing that have been issued but not yet adopted by the Company that would have a material effect on the Company's unaudited condensed consolidated financial statements and related disclosures.

Note 3—Fresh Start Reporting

Fresh Start Reporting

In connection with the Company's emergence from bankruptcy and in accordance with ASC 852, the Company qualified for and applied fresh start reporting on the Emergence Date. The Company was required to apply fresh start reporting due to the fact that (i) the holders of existing voting shares of the Predecessor Company received less than 50% of the voting shares of the Successor Company, and (ii) the reorganization value (defined below) of the Company's assets immediately prior to confirmation of the Plan of $1.4 billion was less than the $2.9 billion of post-petition liabilities and allowed claims.

As a result of the Company qualifying for fresh start reporting, a new reporting entity was considered to have been created; as a result and in accordance with ASC 852, the Company allocated the reorganization value of the Company to its individual assets, including property, plant and equipment, based on their estimated fair values in conformity with ASC *Topic 820–Fair Value Measurement* ("ASC 820") and ASC *Topic 805–Business Combinations* ("ASC 805"). As such, the condensed consolidated financial statements after January 20, 2021 are not comparable with the condensed consolidated financial statements as of or prior to that date.

Reorganization Value

Reorganization value represents the fair value of the Successor Company's assets before considering certain liabilities and is intended to represent the approximate amount a willing buyer would pay for the Company's assets immediately after reorganization. Reorganization value is derived from an estimate of enterprise value, or fair value of the Company's interest-bearing debt and stockholders' equity. As set forth in the Plan and related disclosure statement, the enterprise value of the Successor Company was estimated to be between $875.0 million to $1.275 billion. On the Emergence Date, the Successor Company's estimated enterprise value was $1.052 billion before the consideration of cash and cash equivalents on hand, which falls slightly below the midpoint of this range. The enterprise value was derived from an independent valuation using an income approach to derive the fair value of the Company's assets as of the Emergence Date. On the Emergence Date, pursuant to the terms of the Plan, the Successor Company entered into a $1.0 billion reserve-based credit agreement with an initial borrowing base of $500.0 million. Please see *Note 4—Long-Term Debt* for discussion of the Successor Company's debt.

The Company's principal assets are its oil and natural gas properties. The fair value of proved reserves was estimated using a discounted cash flows approach, which was based on the anticipated future cash flows associated with those proved reserves, risked by reserve category and discounted using a weighted average cost of capital rate of 11.0%. The proved reserve locations included in this analysis were limited to wells included in the Company's five-year development plan. Future prices were based on forward strip price curves (adjusted for basis differentials). The fair value of the Company's unproved reserves was estimated using a discounted cash flows approach. See further discussion below in the section titled "Fresh Start Adjustments."

The following table reconciles the Company's enterprise value to the implied value of Successor equity as of January 20, 2021 (in thousands, except per share data):

	Successor January 20, 2021
Enterprise value	$ 1,052,000
Plus: Cash and cash equivalents	71,793
Plus: General unsecured claims to be satisfied through issuance of equity after Emergence	16,127
Less: Working capital adjustment[1]	(333,938)
Less: Interest bearing liabilities	(265,000)
Less: Fair value of warrants[2]	(20,403)
Implied value of Successor equity after satisfaction of general unsecured claims after Emergence	$ 520,579
Less: General unsecured claims to be satisfied through issuance of equity after Emergence	(16,127)
Implied value of Successor equity as of January 20, 2021	$ 504,452
Common shares of Successor equity as of January 20, 2021	24,729,681
Implied value per common share as of January 20, 2021	$ 20.41

(1) Represents current assets without cash and cash equivalents and restricted cash, current liabilities without asset retirement obligations and the current liability related to the professional fee escrow accrual in "Accounts payable and accrued liabilities," other non-current liabilities, non-current production taxes, and the working capital deficit adjustment of approximately $23.9 million utilized by the valuation specialist to determine enterprise value for the Plan. This adjustment considers the impact of liabilities in excess of normalized working capital to the enterprise value for purposes of calculating implied Successor equity.
(2) Warrants were considered as part of equity on the condensed consolidated balance sheet but are broken out separately here for presentation and disclosure purposes.

The following table reconciles the Company's enterprise value to its reorganization value as of January 20, 2021 (in thousands):

	Successor January 20, 2021
Enterprise value	$ 1,052,000
Plus: Normalized working capital liabilities[1]	176,976
Plus: Asset retirement obligations, current and non-current	87,199
Plus: Cash and cash equivalents	71,793
Reorganization value	$ 1,387,968

(1) Relates to normalized working capital liabilities in the Predecessor ending balance sheet.

Although the Company believes the assumptions and estimates used to develop enterprise value and reorganization value are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating these values are inherently uncertain and require judgment. See below in the section titled "Fresh Start Adjustments" for additional information regarding assumptions used in the valuation of the Company's significant assets and liabilities.

Condensed Consolidated Balance Sheet at the Emergence Date (in thousands)

The adjustments set forth in the following condensed consolidated balance sheet as of January 20, 2021 reflect the consummation of transactions contemplated by the Plan (the "Reorganization Adjustments") and the fair value adjustments as a result of applying fresh start reporting (the "Fresh Start Adjustments"). The explanatory notes highlight methods used to determine fair values or other amounts of the corresponding assets or liabilities, as well as significant assumptions.

	Predecessor	Reorganization Adjustments	Fresh Start Adjustments	Successor
ASSETS				
Current Assets:				
Cash and cash equivalents	$ 246,952	$ (175,159) (a)	$ —	$ 71,793
Restricted cash	—	38,869 (b)	—	38,869
Accounts receivable, net				
Trade	12,500	—	—	12,500
Oil, natural gas and NGL sales	64,698	—	—	64,698
Inventory, prepaid expenses and other	33,524	—	3,470 (r)	36,994
Commodity derivative asset	—	—	—	—
Total Current Assets	357,674	(136,290)	3,470	224,854
Property and Equipment (successful efforts method), at cost:				
Proved oil and gas properties	4,746,225	—	(3,800,981) (s)	945,244
Unproved oil and gas properties	221,247	—	(75,647) (s)	145,600
Wells in progress	136,247	—	(136,247) (s)	—
Less: accumulated depletion, depreciation, amortization and impairment charges	(3,475,279)	—	3,475,279 (s)	—
Net oil and gas properties	1,628,440	—	(537,596)	1,090,844
Other property and equipment, net of accumulated depreciation and impairment charges	56,455	—	350 (t)	56,805
Net Property and Equipment	1,684,895	—	(537,246)	1,147,649
Non-Current Assets:				
Commodity derivative asset	134	—	—	134
Other non-current assets	9,003	6,328 (c)	—	15,331
Total Non-Current Assets	9,137	6,328	—	15,465
Total Assets	$ 2,051,706	$ (129,962)	$ (533,776)	$ 1,387,968
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current Liabilities:				
Accounts payable and accrued liabilities	$ 93,036	$ 58,792 (d)	$ 3,469 (r)	$ 155,297
Revenue payable	68,003	59,750 (e)	—	127,753
Production taxes payable	3,284	132,255 (f)	—	135,539
Commodity derivative liability	7,897	—	—	7,897
Accrued interest payable	2,236	(2,236) (g)	—	—
Asset retirement obligations	—	13,937 (h)	(478) (u)	13,459
DIP Credit Facility	106,727	(106,727) (i)	—	—
Prior Credit Facility	453,872	(453,872) (i)	—	—
Total Current Liabilities	735,055	(298,101)	2,991	439,945
Non-Current Liabilities:				
RBL Credit Facility	—	265,000 (j)	—	265,000
Production taxes payable	38,716	22,405 (f)	—	61,121
Commodity derivative liability	—	—	—	—
Other non-current liabilities	—	23,307 (k)	—	23,307
Asset retirement obligations	—	80,620 (h)	(6,880) (u)	73,740
Deferred tax liability	—	—	—	—
Total Non-Current Liabilities	38,716	391,332	(6,880)	423,168
Liabilities Subject to Compromise	2,135,808	(2,135,808) (l)	—	—
Total Liabilities	2,909,579	(2,042,577)	(3,889)	863,113
Commitments and Contingencies				
Series A Convertible Preferred Stock	192,172	(192,172) (m)	—	—
Stockholders' Equity (Deficit):				
Predecessor common stock	1,336	(1,336) (n)	—	—
Predecessor treasury stock	(170,138)	170,138 (o)	—	—
Predecessor additional paid-in capital	2,140,383	(2,140,383) (n)(o)	—	—
Successor common stock	—	247 (p)	—	247
Successor warrants	—	20,403 (p)	—	20,403
Successor additional paid-in capital	—	504,205 (p)	—	504,205
Accumulated deficit	(3,021,626)	3,551,513 (q)	(529,887) (v)	—
Total Stockholders' Equity (Deficit)	(1,050,045)	2,104,787	(529,887)	524,855
Total Liabilities and Stockholders' Equity (Deficit)	$ 2,051,706	$ (129,962)	$ (533,776)	$ 1,387,968

Reorganization Adjustments

(a) The table below reflects the sources and uses of cash and cash equivalents on the Emergence Date pursuant to the terms of the Plan (in thousands):

Sources:		
Total cash received from the RBL Credit Facility	$	265,000
Total proceeds from backstopped rights offering		200,255
Total proceeds from the general unsecured claims rights offering		218
Total sources of cash		465,473
Uses:		
Payment of DIP Credit Facility, Prior Credit Facility, and related interest		(562,834)
Funding of the professional fee escrow account		(38,869)
Payment of prepetition taxes classified as liabilities subject to compromise		(21,532)
Payment of debt issuance cost associated with the RBL Credit Facility		(6,329)
Payment of contract cure costs classified as liabilities subject to compromise		(5,374)
Payments to professionals at emergence		(5,102)
Payment of the general unsecured claim cash out election for claims classified as liabilities subject to compromise		(592)
Total uses of cash		(640,632)
Net uses of cash	$	(175,159)

(b) Represents the funding of the professional fee escrow account.

(c) Represents $6.3 million of financing costs related to the RBL Credit Facility, which were capitalized as debt issuance costs and will be amortized straight-line to interest expense through the maturity date of July 20, 2024.

(d) Represents amounts shown in “Accounts payable and accrued liabilities” as reorganization adjustments (in thousands):

Reinstatements from liabilities subject to compromise:		
Accounts payable and accrued liabilities	$	29,752
Current portion of a settlement liability		17,700
General unsecured claims to be satisfied through issuance of equity after Emergence		16,127
Other general unsecured claims to be satisfied after Emergence		8,746
Other adjustments:		
Success fees		20,800
Backstop Commitment Agreement premium satisfied in common shares at Emergence		(29,231)
Professional fees paid at Emergence		(5,102)
Total accounts payable and accrued liabilities reorganization adjustments	$	58,792

(e) Represents revenue payables formerly in “Liabilities Subject to Compromise” that have been reinstated at emergence and will be paid out subsequent to emergence.

(f) Represents production taxes payable formerly in “Liabilities Subject to Compromise” that have been reinstated at emergence and will be paid out subsequent to emergence.

(g) Represents the satisfaction upon emergence of the Predecessor Company’s accrued interest payable for the Prior Credit Facility and DIP Credit Facility.

(h) Represents $13.9 million and $80.6 million of the current and non-current portions of asset retirement obligations, respectively, formerly in “Liabilities Subject to Compromise” that have been reinstated at emergence.

(i) Reflects the payment in full of the borrowings outstanding under the Prior Credit Facility and DIP Credit Facility.

(j) Reflects borrowings drawn under the RBL Credit Facility upon emergence.

(k) Represents $19.3 million of the non-current portion of a settlement liability and $4.0 million of other non-current liabilities formerly in “Liabilities Subject to Compromise” that have been reinstated at emergence and will be paid out subsequent to emergence.

(l) As part of the Plan, the Bankruptcy Court approved the settlement of certain claims reported within “Liabilities Subject to Compromise” in the Company's consolidated balance sheet at their respective allowed claim amounts. The table below indicates the reinstatement or disposition of liabilities subject to compromise (in thousands):

Liabilities subject to compromise pre-emergence	$	2,135,808
Amounts reinstated on the Emergence Date:		
Production taxes payable		(154,660)
Asset retirement obligations		(94,557)
Revenue payable		(59,750)
Accounts payable and accrued liabilities		(72,860)
Other non-current liabilities		(23,307)
Total liabilities reinstated		(405,134)
Consideration provided to settle liabilities subject to compromise per the Plan		
Issuance of Successor equity associated with the participation in the backstopped and general unsecured rights offerings		(251,795)
Less proceeds from issuance of Successor equity associated with the backstopped and general unsecured rights offerings		200,473
Issuance of Successor equity to 2024 and 2026 Senior Notes holders, incremental to the backstopped and general unsecured rights offerings, and backstop commitment premium		(156,889)
Issuance of Successor equity to general unsecured claim holders, incremental to the backstopped and general unsecured rights offerings, and backstop commitment premium		(64,857)
Cash payment in settlement of claims and other		(27,498)
Total consideration provided to settle liabilities subject to compromise per the Plan		(300,566)
Gain on settlement of liabilities subject to compromise	$	1,430,108

(m) Pursuant to the terms of the Plan, on the Emergence Date, all Predecessor preferred stock interests were cancelled.

(n) Pursuant to the terms of the Plan, on the Emergence Date, all Predecessor common stock interests were cancelled.

(o) Pursuant to the terms of the Plan, on the Emergence Date, all Predecessor treasury stock interests were cancelled.

(p) Reflects the issuance of Successor equity, including the issuance of 24,729,681 shares of common stock at a par value of $0.01 per share and warrants to purchase 4,358,369 shares of common stock in exchange for claims against or interests in the Debtors pursuant to the Plan. Equity issued is detailed in the table below (in thousands):

Issuance of Successor equity associated with the participation in the backstopped and general unsecured claims rights offerings	$	251,795
Issuance of Successor equity associated with the backstop commitment premium		23,584
Issuance of Successor equity to 2024 and 2026 Senior Notes holders, incremental to the backstopped and general unsecured rights offerings, and backstop commitment premium		156,889
Issuance of Successor equity to general unsecured claims holders, incremental to the backstopped and general unsecured rights offerings, and backstop commitment premium		64,857
Fair value of warrants (Tranche A and B) to Predecessor common and preferred stockholders		20,403
Issuance of Successor equity to Predecessor common stockholders		3,664
Issuance of Successor equity to Predecessor preferred stockholders		3,663
Total Successor equity as of January 20, 2021	$	524,855

(q) The table below reflects the cumulative net impact of the effects on accumulated deficit (in thousands):

Reorganization items, net:		
Gain on settlement of liabilities subject to compromise	$	(1,430,108)
Adjustment to Backstop Commitment Agreement premium		(5,365)
Acceleration of unvested stock compensation		3,468
Success fees		20,800
Impact on reorganization items, net		(1,411,205)
Cancellation of Predecessor equity		(2,140,308)
Net impact on accumulated (deficit)	$	(3,551,513)

Fresh Start Adjustments

(r) Reflects the adjustment to fair value of the Company's line fill inventory based on market prices as of the Emergence Date.

(s) Reflects the adjustments to fair value of the Company's oil and natural gas properties, proved and unproved, as well as the elimination of wells in progress and accumulated depletion, depreciation and amortization.

For purposes of estimating the fair value of the Company's proved oil and gas properties, a discounted cash flows approach was used that estimated the fair value based on the anticipated future cash flows associated with the Company's proved reserves, risked by reserve category and discounted using a weighted average cost of capital rate of 11.0%. The proved reserve locations included in this analysis were limited to wells included in the Company's five-year development plan. Future prices for the income approach were based on forward strip price curves (adjusted for basis differentials) as of the Emergence Date.

In estimating the fair value of the Company's unproved properties, a discounted cash flows approach was used. The approach utilized for proved properties was also consistently utilized for properties that had positive future cash flows associated with reserve locations that did not qualify as proved reserves.

(t) Reflects the fair value adjustment to recognize the Company’s land as of the Emergence Date based on assessed values provided to management by a licensed appraiser. The appraisals utilized the market approach for comparable properties, where there was market comparable data available or the appraiser’s knowledge of the market and the property, to provide an estimated market value where market comparable data was not available.

(u) Reflects the adjustment to fair value of the Company's asset retirement obligations including using a credit-adjusted risk-free rate as of the Emergence Date.

(v) Reflects the net cumulative impact of the fresh start adjustments on accumulated deficit.

Reorganization Items, Net

Any expenses, gains and losses that were realized or incurred between the Petition Date and the Emergence Date and as a direct result of the Chapter 11 Cases were recorded in reorganization items, net in the Company’s consolidated statements of operations. The following table summarizes the components of reorganization items, net for the periods presented (in thousands):

	Predecessor
	For the Period from January 1 through January 20, 2021
Gain on settlement of liabilities subject to compromise	$ 1,430,108
Adjustment to Backstop Commitment Agreement premium	5,365
Acceleration of unvested stock compensation	(3,468)
Professional fees	(7,410)
Success fees	(20,800)
Fresh start valuation adjustment	(529,887)
Total reorganization items, net	$ 873,908

Note 4—Long-Term Debt

The Company's long-term debt consisted of the following (in thousands):

	Successor June 30, 2021	Predecessor December 31, 2020
RBL Credit Facility	$ 90,000	$ —
DIP Credit Facility	—	106,727
Prior Credit Facility	—	453,747
2024 Senior Notes	—	400,000
2026 Senior Notes	—	700,189
Total principal	90,000	1,660,663
Unamortized debt issuance costs(1)	—	—
Total debt, prior to reclassification to "Liabilities Subject to Compromise"	90,000	1,660,663
Less amounts reclassified to "Liabilities Subject to Compromise"(2)	—	(1,100,189)
Total debt not subject to compromise(3)	90,000	560,474
Less current portion of long-term debt	—	(560,474)
Total long-term debt	$ 90,000	$ —

(1) As a result of the Chapter 11 Cases and the adoption of ASC 852, the Company wrote off all unamortized debt issuance cost balances to reorganization items, net in the consolidated statements of operations during the year ended December 31, 2020.
(2) As of December 31, 2020, amounts reclassified to "Liabilities Subject to Compromise" included the principal balances of the Predecessor Company's 2024 and 2026 Senior Notes.
(3) Total debt not subject to compromise includes all borrowings outstanding under the Prior Credit Facility and DIP Credit Facility.

RBL Credit Facility

On the Emergence Date, pursuant to the terms of the Plan, the Successor Company entered into a $1.0 billion reserve-based credit agreement ("RBL Credit Agreement") with Wells Fargo Bank, National Association ("RBL Credit Facility") with an initial borrowing base of $500.0 million. The borrowing base is redetermined semiannually on or around May 1 and November 1 of each year, with one interim "wildcard" redetermination available to each of the Successor Company and its administrative agent between scheduled redeterminations during any 12-month period. On May 6, 2021, the Successor Company's borrowing base was reaffirmed at $500.0 million. The next scheduled redetermination will be on or around November 1, 2021.

As of the date of this filing, the Successor Company has drawn $70.0 million on the RBL Credit Facility. Total funds available for borrowing under the Successor Company's RBL Credit Facility, after giving effect to an aggregate of $0.5 million of undrawn letters of credit, were $429.5 million as of the date of this filing.

The RBL Credit Facility provides for a $50.0 million sub-limit of the aggregate commitments that is available for the issuance of letters of credit. The RBL Credit Facility bears interest either at a rate equal to (i) LIBOR plus an applicable margin that varies from 3.00% to 4.00% per annum, or (ii) a base rate plus an applicable margin that varies from 2.00% to 3.00% per annum. The RBL Credit Facility matures on July 20, 2024. The grid below shows the base rate margin and Eurodollar margin depending on the applicable borrowing base utilization percentage as of the date of this filing:

RBL Credit Facility Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	Utilization	Base Rate Margin	Eurodollar Margin	Commitment Fee Rate
Level 1	<25%	2.00 %	3.00 %	0.50 %
Level 2	≥ 25% < 50%	2.25 %	3.25 %	0.50 %
Level 3	≥ 50% < 75%	2.50 %	3.50 %	0.50 %
Level 4	≥ 75% < 90%	2.75 %	3.75 %	0.50 %
Level 5	≥90%	3.00 %	4.00 %	0.50 %

The RBL Credit Facility requires the Successor Company to maintain (i) a consolidated net leverage ratio of less than or equal to 3.00 to 1.00, and (ii) a consolidated current ratio of greater than or equal to 1.00 to 1.00. Per the RBL Credit Agreement, for the purpose of calculating the current ratio for fiscal quarters ending March 31, 2021 and June 30, 2021, all ad valorem, severance or tax liabilities can be excluded from current liabilities in the calculation of the current ratio.

The Successor Company is required to pay a commitment fee of 0.50% per annum on the actual daily unused portion of the current aggregate commitments under the RBL Credit Facility. The Successor Company is also required to pay customary letter of credit and fronting fees.

The RBL Credit Agreement also contains customary affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws and anti-corruption laws), delivery of quarterly and annual financial statements and borrowing base certificates, conduct of business, maintenance of property, maintenance of insurance, restrictions on the incurrence of liens, indebtedness, asset dispositions, restricted payments, and other customary covenants.

Additionally, the RBL Credit Agreement contains customary events of default and remedies for credit facilities of this nature. If the Successor Company does not comply with the financial and other covenants in the RBL Credit Agreement, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Credit Agreement and any outstanding unfunded commitments may be terminated.

Prior Credit Facility, DIP Credit Facility, 2024 Senior Notes and 2026 Senior Notes

Information pertaining to these debt facilities can be found in the Company’s Annual Report. The Company’s obligations under its Prior Credit Facility, DIP Credit Facility, 2024 Senior Notes and 2026 Senior Notes were settled at the Effective Date.

Debt Issuance Costs

Successor Company debt issuance costs include origination, legal and other fees incurred in connection with the Successor Company’s RBL Credit Facility. As of June 30, 2021, the Successor Company had debt issuance costs, net of accumulated amortization, of $5.5 million, which has been reflected on the Successor Company's condensed consolidated balance sheets within the line item “Other non-current assets.” For the period from January 1, 2021 to January 20, 2021, the Predecessor Company recorded amortization expense related to debt issuance costs of $0.1 million. For the three months ended June 30, 2021 and for the period from January 21, 2021 to June 30, 2021, the Successor Company recorded amortization expense related to debt issuance costs of $0.5 million and $0.9 million, respectively. For the three and six months ended June 30, 2020, the Predecessor Company recorded amortization expense related to debt issuance costs of $1.9 million and $3.2 million, respectively.

Predecessor Company debt issuance costs include origination, legal and other fees incurred in connection with the Predecessor Company’s Prior Credit Facility, DIP Credit Facility, 2024 Senior Notes and 2026 Senior Notes. As a result of the bankruptcy, the Company wrote off $13.3 million in unamortized debt issuance costs on the 2024 and 2026 Senior Notes to reorganization items, net in the condensed consolidated statements of operations for the three and six months ending June 30, 2020.

Interest Incurred on Long-Term Debt

For the period from January 1, 2021 to January 20, 2021, the Predecessor Company incurred interest expense on long-term debt of $1.5 million and capitalized interest expense on long-term debt of $0.1 million. For the three months ended June 30, 2021, the Successor Company incurred interest expense on long-term debt of $1.8 million and capitalized interest expense on long-term debt of $0.1 million. For the period from January 21, 2021 to June 30, 2021, the Successor Company incurred interest expense on long-term debt of $4.4 million and capitalized interest expense on long-term debt of $0.1 million. For the three and six months ended June 30, 2020, the Predecessor Company incurred interest expense on long-term debt of $20.2 million and $42.5 million, respectively. Absent the automatic stay, interest expense for the three and six months ended June 30, 2020 would have been $23.2 million and $44.5 million, respectively. For the three and six months ended June 30, 2020, the Predecessor Company capitalized interest expense on long-term debt of $1.9 million and $4.0 million, respectively.

Note 5—Commodity Derivative Instruments

The Company's open commodity derivative contracts by quarter as of June 30, 2021 are summarized below:

	9/30/2021	12/31/2021	3/31/2022	6/30/2022	9/30/2022	12/31/2022	3/31/2023
NYMEX WTI Crude Swaps:							
Notional volume (Bbl)	1,153,000	1,041,000	828,000	—	—	—	—
Weighted average fixed price ($/Bbl)	$ 49.64	$ 50.01	$ 50.05	$ —	$ —	$ —	$ —
NYMEX WTI Crude Purchased Puts:							
Notional volume (Bbl)	—	—	—	345,839	320,247	297,903	94,820
Weighted average purchased put price ($/Bbl)	$ —	$ —	$ —	$ 40.00	$ 40.00	$ 40.00	$ 40.00
NYMEX WTI Crude Sold Calls:							
Notional volume (Bbl)	—	—	—	345,839	320,247	297,903	94,820
Weighted average sold call price ($/Bbl)	$ —	$ —	$ —	$ 72.70	$ 72.70	$ 72.70	$ 72.70
NYMEX HH Natural Gas Swaps:							
Notional volume (MMBtu)	8,482,141	7,904,240	6,468,277	—	—	—	—
Weighted average fixed price ($/MMBtu)	$ 2.93	$ 2.93	$ 3.00	$ —	$ —	$ —	$ —
NYMEX HH Natural Gas Purchased Puts:							
Notional volume (MMBtu)	—	—	—	2,764,135	2,614,602	2,477,469	797,160
Weighted average purchased put price ($/MMBtu)	$ —	$ —	$ —	$ 2.00	$ 2.00	$ 2.00	$ 2.00
NYMEX HH Natural Gas Sold Calls:							
Notional volume (MMBtu)	—	—	—	2,764,135	2,614,602	2,477,469	797,160
Weighted average sold call price ($/MMBtu)	$ —	$ —	$ —	$ 3.25	$ 3.25	$ 3.25	$ 3.25

The following tables detail the fair value of the Company's derivative instruments, including the gross amounts and adjustments made to net the derivative instruments for the presentation in the condensed consolidated balance sheets (in thousands):

Location on Balance Sheet	Gross Amounts of Recognized Assets and Liabilities	Gross Amounts Offsets in the Balance Sheet[1]	Net Amounts of Assets and Liabilities Presented in the Balance Sheet	Gross Amounts not Offset in the Balance Sheet[2]	Net Amounts[3]
	Successor as of June 30, 2021				
Current assets	$ 375	$ (375)	$ —	$ —	$ —
Non-current assets	1,207	(1,207)	—	—	—
Current liabilities	(79,290)	375	(78,915)	—	(82,217)
Non-current liabilities	(4,509)	1,207	(3,302)	—	—
	Predecessor as of December 31, 2020				
Current assets	$ 8,372	$ (1,401)	$ 6,971	$ —	$ 6,971
Non-current assets	—	—	—	—	—
Current liabilities	(3,548)	1,401	(2,147)	—	(2,147)
Non-current liabilities	—	—	—	—	—

(1) Agreements are in place that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.
(2) Netting for balance sheet presentation is performed by current and non-current classification. This adjustment represents amounts subject to an enforceable master netting arrangement, which are not netted on the condensed consolidated balance sheets. There are no amounts of related financial collateral received or pledged.
(3) Net amounts are not split by current and non-current. All counterparties in a net asset position are shown in the current asset line, and all counterparties in a net liability position are shown in the current liability line item.

Commodity derivatives gain (loss) are included in the Other income (expense) section of the condensed consolidated statements of operations. The table below sets forth the commodity derivatives gain (loss) for the periods presented (in thousands).

	Successor	Predecessor
	For the Three Months Ended June 30,	For the Three Months Ended June 30,
	2021	2020
Commodity derivative loss	$ (75,839)	$ (69,301)

	Successor	Predecessor	
	For the Period from January 21 through June 30,	For the Period from January 1 through January 20,	For the Six Months Ended June 30,
	2021	2021	2020
Commodity derivative gain (loss)	$ (104,325)	$ (12,586)	$ 193,714

Note 6—Asset Retirement Obligations

The Company’s asset retirement obligations (“ARO”) represent the present value of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The current and non-current portions as of December 31, 2020 (Predecessor) were $14.3 million and $80.5 million, respectively, and have been included in “Liabilities Subject to Compromise” in the condensed consolidated balance sheets as of that balance sheet date. The following table provides a reconciliation of the Company’s ARO for the periods presented (in thousands):

Asset retirement obligations at December 31, 2020 (Predecessor)	$	94,769
Liabilities settled		(545)
Accretion expense		333
Asset retirement obligations at January 20, 2021 (Predecessor)		94,557
Fresh start adjustment(1)		(7,358)
Asset retirement obligations at January 20, 2021 (Predecessor)		87,199
Asset retirement obligations at January 21, 2021 (Successor)		87,199
Liabilities incurred or acquired		138
Liabilities settled		(2,541)
Revisions in estimated cash flows		651
Accretion expense		3,267
Asset retirement obligations at June 30, 2021 (Successor)	$	88,714

(1) Refer to *Note 3—Fresh Start Reporting* for more information on fresh start adjustments.

Note 7—Fair Value Measurements

The following table (in thousands) presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis, by level within the fair value hierarchy:

	Successor				**Predecessor**			
	Fair Value Measurement at June 30, 2021				**Fair Value Measurement at December 31, 2020**			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivative assets	$ —	$ —	$ —	$ —	$ —	$ 6,971	$ —	$ 6,971
Commodity derivative liabilities	—	82,217	—	82,217	—	2,147	—	2,147

The following table (in thousands) presents the fair value of the Company's financial instruments and carrying value. This table does not impact the Company's financial position, results of operations or cash flows.

	Successor		**Predecessor**	
	At June 30, 2021		**At December 31, 2020**	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
RBL Credit Facility	$ 90,000	$ 90,000	$ —	$ —
Prior Credit Facility	—	—	453,747	453,747
DIP Credit Facility	—	—	106,727	106,727
2024 Senior Notes	—	—	400,000	70,732
2026 Senior Notes	—	—	700,189	123,408

Non-Recurring Fair Value Measurements

The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The Company uses an income approach analysis based on the net discounted future cash flows of producing property. The future cash flows are based on management's estimates for the future. The unobservable inputs listed below are Level 3 inputs within the fair value hierarchy and include:

- estimates of oil and gas production, as the case may be, from the Company's reserve reports;
- commodity prices based on the sales contract terms and forward price curves;
- operating and development costs; and,

- a discount rate based on a market-based weighted average cost of capital.

For both the periods from January 1, 2021 to January 20, 2021 and January 21, 2021 to June 30, 2021, the Company recognized no impairment expense on their proved oil and gas properties. For the three and six months ended June 30, 2020, the Predecessor Company recognized $0.8 million and $1.6 million, respectively, in impairment expense on its proved oil and gas properties related to impairment of assets in its northern field as the fair value did not exceed the Predecessor Company's carrying amount associated with its proved oil and gas properties in its northern field.

See *Note 3—Fresh Start Reporting* for discussion of the revaluation of the Company’s oil and gas properties upon emergence from bankruptcy.

Note 8—Income Taxes

The Company computes an estimated annual effective tax rate (“AETR”) each quarter based on the current and forecasted operating results. The income tax expense or benefit associated with the interim period is computed using the most recent estimated AETR applied to the year-to-date ordinary income or loss, plus the tax effect of any significant or infrequently occurring items recorded during the interim period. The computation of the estimated AETR at each interim period requires certain estimates and significant judgements including, but not limited to, the expected operating income (loss) for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent differences and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained, and additional information becomes known or as the tax environment changes.

The effective combined U.S. federal and state income tax rate for the following periods were as follows:

- For the period from January 1, 2021 to January 20, 2021: zero
- For the three months ended June 30, 2021: 16.29%
- For the period from January 21, 2021 to June 30, 2021: 19.90%
- For the three months ended June 30, 2020: zero
- For the six months ended June 30, 2020: (0.80)%

The effective rate differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income due to (i) the effect of a full valuation allowance in effect at June 30, 2021, and (ii) the effects of state taxes, permanent taxable differences, and income attributable to non-controlling interest for the six months ended June 30, 2020. Net tax expense for the period January 1, 2021 to January 20, 2021 was reduced to zero due to the valuation allowance. Current tax expense for the period January 21, 2021 to June 30, 2021 was $28.1 million primarily as a result of net operating loss (“NOL”) carryovers limited under Section 382 of the Internal Revenue Service Code of 1986, as amended (“IRC”) due to the change in control as referenced in *Note 3—Fresh Start Reporting*.

As described in *Note 1—Business and Organization—Voluntary Reorganization under Chapter 11 of the Bankruptcy Code* in the Company’s filed Form 10-Q from the first quarter of 2021, in accordance with the Plan, the Company’s 2024 and 2026 Senior Notes were canceled and exchanged for New Common Stock. Absent an exception, a debtor recognizes cancellation of indebtedness income (“CODI”) upon discharge of its outstanding indebtedness for an amount of consideration that is less than its adjusted issue price. The Internal Revenue Code (“IRC”) provides that a debtor in a Chapter 11 bankruptcy case may exclude CODI from taxable income but must reduce certain of its tax attributes by the amount of any CODI realized as a result of the consummation of a plan of reorganization. The amount of CODI realized by a taxpayer is determined based on the fair market value of the consideration received by the creditors in settlement of outstanding indebtedness. Upon emergence from Chapter 11 bankruptcy proceedings, the CODI may reduce some or all of the amount of prior tax attributes, which can include net operating losses, capital losses, alternative minimum tax credits and tax basis in assets. The actual reduction in tax attributes does not occur until January 1, 2022.

The Company has evaluated the impact of the reorganization, including the change in control, resulting from its emergence from bankruptcy. From an income tax perspective, the most significant impact is attributable to our carryover tax attributes associated with our net operating losses. On the date of emergence, the estimated NOL was approximately

$1.3 billion. The Company believes that the Successor Company will be able to fully absorb the cancellation of debt income realized by the Predecessor Company in connection with the reorganization with its adjusted NOL carryovers. The amount of the remaining NOL carryovers will be limited under Section 382 of the IRC due to the change in control as referenced in *Note 3—Fresh Start Reporting*. As the tax basis of the Company's assets, primarily our oil and gas properties, is in excess of the carrying value, as adjusted in the fresh-start accounting process, the Successor Company is in a net deferred tax asset position. Per authoritative guidance, historical results along with expected market conditions known on the date of measurement, it is more likely than not that the Company will not realize future income tax benefits from the additional tax basis and its remaining NOL carryovers. This is periodically reassessed and could change. Accordingly, the Company has provided for a full valuation allowance of the underlying deferred tax assets.

Note 9—Stock-Based Compensation

2021 Long-Term Incentive Plan

On January 20, 2021, as part of the emergence from bankruptcy, the Board adopted the Extraction 2021 Long-Term Incentive Plan (the “2021 LTIP”) with a share reserve equal to 3,038,657 shares of New Common Stock. The 2021 LTIP provides for the grant of restricted stock units, restricted stock awards, stock options, stock appreciation rights, performance awards and cash awards to the Company’s employees and non-employee Board members. At emergence, the Successor Company granted awards under the 2021 LTIP to its directors, officers and employees, including restricted stock units, performance stock units and deferred stock units.

2016 Long-Term Incentive Plan

In October 2016, the Predecessor Company’s Board adopted the Extraction 2016 Long-Term Incentive Plan (the “2016 LTIP”), pursuant to which employees, consultants, and directors of the Predecessor Company and its affiliates performing services for the Predecessor Company were eligible to receive awards. The 2016 LTIP provided for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, other stock-based awards, substitute awards, annual incentive awards, and performance awards intended to align the interests of participants with those of stockholders. In May 2019, the Predecessor Company’s stockholders approved the amendment and restatement of the 2016 LTIP. The amended and restated 2016 LTIP provided a total reserve of 32.2 million shares of the Predecessor Common Stock for issuance pursuant to awards under the 2016 LTIP. Extraction granted awards under the 2016 LTIP to certain directors, officers and employees, including stock options, restricted stock units, performance stock awards, performance stock units, performance cash awards and cash awards. Effective January 20, 2021, as part of the emergence from bankruptcy, the 2016 LTIP was terminated and no longer in effect and all outstanding awards were cancelled.

Successor Company Restricted Stock Units (“RSUs”)

RSUs issued under the 2021 LTIP generally vest over either a one or three-year service period, with either 100% vesting in year one or one-third, one-third and one-third of the units vesting in years one, two and three, respectively. Grant date fair value was determined based on the value of the Successor Company’s New Common Stock pursuant to the terms of the 2021 LTIP. The Successor Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Successor Company recorded $1.7 million and $3.1 million of stock-based compensation costs related to Successor Company RSUs for the three months ended June 30, 2021 and for the period from January 21, 2021 through June 30, 2021, respectively. These costs were included in the condensed consolidated statements of operations within the “General and administrative expense” line item. As of June 30, 2021, there was $4.9 million of total unrecognized compensation cost related to the unvested Successor Company RSUs granted to certain directors, officers and employees that is expected to be recognized over a weighted average period of 1.0 year. The following table summarizes the Successor Company’s RSU activity for the period shown and provides information for the Successor Company’s RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested Successor Company RSUs at January 21, 2021	—	$ —
Granted	394,795	20.46
Forfeited	(6,799)	20.41
Vested	—	—
Non-vested Successor Company RSUs at June 30, 2021	387,996	$ 20.46

Predecessor Company RSUs

RSUs issued under the 2016 LTIP generally vested over either a one or three-year service period, with either 100% vesting in year one or 25%, 25% and 50% of the units vesting in years one, two and three, respectively. Grant date fair value was determined based on the value of the Predecessor Common Stock pursuant to the terms of the 2016 LTIP. The Predecessor Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Predecessor Company recorded $0.2 million of stock-based compensation costs related to Predecessor Company RSUs for the period from January 1, 2021 through January 20, 2021, as compared to $1.7 million and $2.5 million for the three and six months ended June 30, 2020, respectively. These costs were included in the condensed consolidated statements of operations within the "General and administrative expense" line item. The following table summarizes the Predecessor Company's RSU activity for the period shown and provides information for the Predecessor Company's RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested Predecessor Company RSUs at January 1, 2021	1,185,351	$ 6.99
Vested	(4,500)	8.70
Cancelled at emergence from bankruptcy	(1,180,851)	6.98
Non-vested Predecessor Company RSUs at January 20, 2021	—	$ —

Successor Company Performance Unit Awards ("PSUs")

Upon emergence from bankruptcy on January 20, 2021, the Successor Company granted PSUs to certain executives under the 2021 LTIP. The number of shares of New Common Stock that may be issued to settle these various PSUs ranges from zero to two times the number of PSUs awarded. Generally, the shares issued for PSUs are determined based on the satisfaction of a time-based vesting schedule and absolute total stockholder return ("ATSR") measured over a three-year period, and vest in their entirety at the end of the three-year measurement period. Any PSUs that have not vested at the end of the applicable measurement period are forfeited. As the ATSR vesting criterion are linked to the Successor Company's share price, it is considered a market condition for purposes of calculating the grant-date fair value of the awards.

The fair value of the Successor Company's PSUs was measured at the grant date with a stochastic process method using a Monte Carlo simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. Those outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Successor Company's PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, and because future stock prices are stochastic, the stochastic method, specifically the Monte Carlo Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the measurement period as well as the volatilities for each of the Company's peers.

The Successor Company recorded $0.5 million and $0.9 million of stock-based compensation costs related to Successor Company PSUs for the three months ended June 30, 2021 and for the period from January 21, 2021 through June 30, 2021, respectively. These costs were included in the condensed consolidated statements of operations within the "General and administrative expense" line item. As of June 30, 2021, there was $5.5 million of total unrecognized compensation cost related to the unvested Successor Company PSUs granted to certain executives that is expected to be recognized over a weighted average period of 2.6 years. The Successor Company's PSUs will be settled by issuing New Common Stock. The following table summarizes the Successor Company's PSU activity for the period shown and provides information for the Successor Company's PSUs outstanding at the dates indicated.

	Number of Shares[(1)]	Weighted Average Grant Date Fair Value
Non-vested Successor Company PSUs at January 21, 2021	—	$ —
Granted	230,850	28.11
Forfeited	—	—
Vested	—	—
Non-vested Successor Company PSUs at June 30, 2021	230,850	$ 28.11

(1) The number of awards assumes that the associated maximum vesting condition is met at the target amount. The final number of shares of New Common Stock issued may vary depending on the performance multiplier, which ranges from zero to two for the Successor Company's 2021 PSU grants, depending on the level of satisfaction of the vesting condition.

Predecessor Company Performance Stock Awards ("PSAs")

The Predecessor Company granted PSAs to certain executives under the 2016 LTIP in October 2017, March 2018, April 2019 and March 2020. The number of shares of Predecessor Common Stock that may be issued to settle these various PSAs ranges from zero to two times the number of PSAs awarded. PSAs that settle in cash were presented as liability awards. Generally, the shares issued for PSAs were determined based on the satisfaction of a time-based vesting schedule and a weighting of one or more of the following: (i) ATSR, (ii) relative total stockholder return ("RTSR"), as compared to the Predecessor Company's peer group and (iii) cash return on capital invested ("CROCI") or return on invested capital ("ROIC") measured over a three-year period and vest in their entirety at the end of the three-year measurement period. Any PSAs that have not vested at the end of the applicable measurement period were forfeited. The vesting criterion that was associated with the RTSR was based on a comparison of the Predecessor Company's total shareholder return for the measurement period compared to that of a group of peer companies for the same measurement period. As the ATSR and RTSR vesting criteria were linked to the Predecessor Company's share price, they each were considered a market condition for purposes of calculating the grant-date fair value of the awards. The vesting criterion that was associated with the CROCI and ROIC were considered a performance condition for purposes of calculating the grant-date fair value of the awards.

The fair value of the Predecessor Company's PSAs were measured at the grant date with a stochastic process method using a Monte Carlo simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. Those outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Predecessor Company's PSAs, the Company cannot predict with certainty the path its stock price or the stock prices of its peer will take over the performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, and because future stock prices are stochastic, the stochastic method, specifically the Monte Carlo Model, is deemed an appropriate method by which to determine the fair value of the PSAs. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the measurement period as well as the volatilities for each of the Company's peers.

The Predecessor Company recorded $0.1 million of stock-based compensation costs related to Predecessor Company PSAs for the period from January 1, 2021 through January 20, 2021, as compared to $0.8 million and $0.1 million for the three and six months ended June 30, 2020, respectively. These costs were included in the condensed consolidated statements of operations within the "General and administrative expense" line item. As of June 30, 2021, there was no unrecognized compensation cost related to the unvested Predecessor Company PSAs granted to certain executives as they were all cancelled at emergence. The following table summarizes the Predecessor Company's PSA activity for the period shown and provides information for the Predecessor Company's PSAs outstanding at the dates indicated.

	Number of Shares[1]	Weighted Average Grant Date Fair Value
Non-vested Predecessor Company PSAs at January 1, 2021	1,196,279	$ 5.32
Cancelled at emergence from bankruptcy	(1,196,279)	5.32
Non-vested Predecessor Company PSAs at January 20, 2021	—	$ —

(1) The number of awards assumed that the associated maximum vesting condition is met at the target amount. The final number of shares of the Predecessor Common Stock issued would have varied depending on the performance multiplier, which ranged from zero to one for the 2017 and 2018 grants and ranged from zero to two for the 2019 and 2020 grants, which would have depended on the level of satisfaction of the vesting condition.

Successor Company Deferred Stock Units ("DSUs")

Upon emergence from bankruptcy on January 20, 2021, a new Board was appointed and each Board member (except the CEO) was granted 16,800 Successor Company DSUs, which vest in quarterly installments over a one-year period following the grant date. The Successor Company DSUs will be settled in shares of New Common Stock upon the Board member's departure from the Company; thus, these DSUs may not be included in the Successor Company's issued and outstanding shares, potentially for several years. Grant date fair value was determined based on the value of the Successor Company's New Common Stock pursuant to the terms of the 2021 LTIP. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Successor Company recorded $0.5 million and $0.9 million of stock-based compensation costs related to Successor Company DSUs for the three months ended June 30, 2021 and for the period from January 21, 2021 through June 30, 2021, respectively. These costs were included in the condensed consolidated statements of operations within the "General and administrative expense" line item. As of June 30, 2021, there was $1.1 million of total unrecognized compensation cost related to the unvested Successor Company DSUs granted to certain directors that is expected to be recognized over a weighted average period of 0.6 years. The following table summarizes the Successor Company's DSU activity for the period shown and provides information for the Successor Company's DSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested Successor Company Deferred Stock Units at January 21, 2021	—	$ —
Granted	100,800	20.41
Forfeited	—	—
Vested	(25,200)	20.41
Non-vested Successor Company Deferred Stock Units June 30, 2021	75,600	$ 20.41

Note 10—Equity

Common Stock

On the Emergence Date, the Successor Company filed an amended and restated certificate of incorporation with the Delaware Secretary of State to provide for, among other things, the authority to issue a total of 950,000,000 shares of all classes of capital stock of which 900,000,000 shares are common stock, par value $0.01 per share (the "New Common Stock") and 50,000,000 shares are preferred stock, par value $0.01 per share. Upon emergence from the Chapter 11 Cases, all existing shares of the Predecessor Common Stock and the Predecessor Preferred Stock were cancelled, and the Successor Company issued 25,703,212 shares of New Common Stock during the first quarter of 2021. During the second quarter of 2021, the Company issued 133,705 shares of New Common Stock to settle general unsecured claims. As of June 30, 2021, the Company expects to issue an additional 136,943 shares of New Common Stock to settle general unsecured claims. See *Note 1—Business and Organization —Voluntary Reorganization under Chapter 11 of the Bankruptcy Code* in the Company's filed Form 10-Q from the first quarter of 2021 and *Note 3—Fresh Start Reporting* for more information.

Series A Preferred Stock

In connection with emergence from the Chapter 11 Cases on January 20, 2021, and pursuant to the Plan, each share of the Predecessor Preferred Stock was canceled, released and extinguished, and is of no further force or effect.

Warrants

On the Emergence Date and pursuant to the Plan, the Successor Company entered into warrant agreements with American Stock Transfer & Trust Company, LLC, as warrant agent, which provided for (i) the Successor Company's issuance of up to an aggregate of 2,905,567 Tranche A Warrants to purchase the New Common Stock (the "Tranche A Warrants") to certain former holders of the Predecessor Common Stock and (ii) the Successor Company's issuance of up to an aggregate of 1,452,802 Tranche B warrants to purchase New Common Stock (the "Tranche B Warrants" and, together with the Tranche A Warrants, the "New Warrants") to certain former holders of the Predecessor Common Stock.

The Tranche A Warrants are exercisable from the date of issuance until the fourth anniversary of the Emergence Date, at which time all unexercised Tranche A Warrants will expire, and the rights of the holders of such warrants to purchase New Common Stock will terminate. The Tranche A Warrants are initially exercisable for one share of New Common Stock per Tranche A Warrant at an initial exercise price of $107.64 per Tranche A Warrant (the "Tranche A Exercise Price").

The Tranche B Warrants are exercisable from the date of issuance until the fifth anniversary of the Emergence Date, at which time all unexercised Tranche B Warrants will expire, and the rights of the holders of such warrants to purchase New Common Stock will terminate. The Tranche B Warrants are initially exercisable for one share of New Common Stock per Tranche B Warrant at an initial exercise price of $122.32 per Tranche B Warrant (the "Tranche B Exercise Price" and together with the Tranche A Exercise Price, the "Exercise Prices").

Pursuant to the warrant agreements, no holder of a New Warrant, by virtue of holding or having a beneficial interest in a New Warrant, will have the right to vote, receive dividends, receive notice as stockholders with respect to any meeting of stockholders for the election of the Successor Company's directors or any other matter, or exercise any rights whatsoever as a stockholder of the Successor Company unless, until and only to the extent such holders become holders of record of shares of New Common Stock issued upon settlement of the New Warrants.

The number of shares of New Common Stock for which a New Warrant is exercisable, and the Exercise Prices, are subject to adjustment from time to time upon the occurrence of certain events, including stock splits, reverse stock splits or stock dividends to holders of New Common Stock or a reclassification in respect of New Common Stock.

Upon completion of the BCEI Merger, the current warrant structure described above could result in a modification.

Note 11—Earnings (Loss) Per Share

The basic weighted average shares outstanding calculation is based on the actual days in which the shares were outstanding. The components of basic and diluted earnings (loss) per share ("EPS") were as follows (in thousands, except per share data):

	Successor	Predecessor
	For the Three Months Ended June 30,	For the Three Months Ended June 30,
	2021	2020
Basic and Diluted Income (Loss) Per Share		
Net income (loss)	$ 24,544	$ (291,934)
Less: Adjustment to reflect Series A Preferred Stock dividends	—	(4,001)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	—	(1,817)
Adjusted net income (loss) available to common shareholders, basic and diluted	$ 24,544	$ (297,752)
Denominator		
Weighted average common shares outstanding, basic(1)(2)	25,777	138,163
Weighted average common shares outstanding, diluted	26,429	138,163
Income (Loss) Per Common Share		
Basic	$ 0.95	$ (2.16)
Diluted	$ 0.93	$ (2.16)

(1) For the three months ended June 30, 2021, 651,924 dilutive shares, including restricted stock units, performance stock units and deferred stock units outstanding, were included in the calculation above.
(2) For the three months ended June 30, 2020, 6,532,472 potentially dilutive shares, including restricted stock awards and stock options outstanding, were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 11,472,445 common shares associated with the assumed conversion of Predecessor Preferred Stock were also excluded, as they would have had an anti-dilutive effect on EPS.

	Successor	Predecessor	
	For the Period from January 21 through June 30,	For the Period from January 1 through January 20,	For the Six Months Ended June 30,
	2021	2021	2020
Basic and Diluted Income (Loss) Per Share			
Net income (loss)	$ 113,098	$ 870,970	$ (282,897)
Less: Noncontrolling interest	—	—	(6,160)
Less: Adjustment to reflect Series A Preferred Stock dividends	—	—	(8,749)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	—	(418)	(3,587)
Adjusted net income (loss) available to common shareholders, basic and diluted	$ 113,098	$ 870,552	$ (301,393)
Denominator			
Weighted average common shares outstanding, basic(1)(2)(3)	25,655	136,589	137,945
Weighted average common shares outstanding, diluted	26,262	136,589	137,945
Income (Loss) Per Common Share			
Basic	$ 4.41	$ 6.37	$ (2.18)
Diluted	$ 4.31	$ 6.37	$ (2.18)

(1) For the period from January 21, 2021 through June 30, 2021, 607,273 dilutive shares, including restricted stock units, performance stock units and deferred stock units outstanding, were included in the calculation above.
(2) For the period from January 1, 2021 to January 20, 2021, 7,138,153 potentially dilutive shares, including restricted stock awards and stock options outstanding, were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 11,472,445 common shares associated with the assumed conversion of Predecessor Preferred Stock were also excluded, as they would have had an anti-dilutive effect on EPS.
(3) For the six months ended June 30, 2020, 6,532,472 potentially dilutive shares, including restricted stock awards and stock options outstanding, were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 11,472,445 common shares associated with the assumed conversion of Predecessor Preferred Stock were also excluded, as they would have had an anti-dilutive effect on EPS.

Note 12—Commitments and Contingencies

General

As is customary in the oil and gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not meet such commitments, the acreage positions or wells may be lost, or the Company may be required to pay damages if certain performance conditions are not met.

Drilling Rigs

As of June 30, 2021, the Company was subject to no drilling rig commitments.

Leases

The Company has entered into operating leases for certain compressors and office facilities and equipment. Maturities of operating lease liabilities associated with right-of-use assets and including imputed interest were as follows (in thousands):

	Successor
	As of June 30, 2021
2021 - remaining	$ 4,537
2022	3,592
2023	701
2024	—
Thereafter	—
Total lease payments	8,830
Less imputed interest(1)	(402)
Present value of lease liabilities	$ 8,428

(1) Calculated using the estimated interest rate for each lease.

Delivery Commitments

The Predecessor Company entered into a long-term gas gathering and processing agreement (the “Gathering Agreement”) with a third-party midstream provider in February 2019. The Gathering Agreement commenced in January 2020 and has a term of ten years with an annual minimum volume commitment of 13.0 Bcf. The Gathering Agreement also includes a commitment to sell take-in-kind NGLs from other processing agreements of 4,000 Bbl/d in the first year of the Gathering Agreement and 7,500 Bbl/d in years two through seven of the Gathering Agreement with the ability to roll forward up to a 10% shortfall in a given month to the subsequent month. On December 23, 2020, the Predecessor Company and the counterparty entered into a settlement and amended the Gathering Agreement (the “Settlement and Amendment”). No changes were made to the Company’s annual minimum volume commitment as a result of the settlement and amendment.

In December 2016 and August 2017, the Predecessor Company agreed with several third-party producers and a midstream provider to expand natural gas gathering and processing capacity in the DJ Basin, including through the addition of two new processing plants as well as the expansion of related gathering systems. The first plant commenced operations in August 2018 and the second plant commenced operations in July 2019. The Company’s share of these commitments requires an incremental 51.5 and 20.6 MMcf per day, respectively, over a baseline volume of 65 MMcf per day for a period of seven years following the in-service dates of the plants. The Company may be required to pay a shortfall fee for any incremental volume deficiencies under these commitments. These contractual obligations can be reduced by the Company's proportionate share of the collective volumes delivered to the plants by other third-party incremental volumes available to the midstream provider at the new facilities that are in excess of the total commitments. The Company is also required for the first three years of each contract to guarantee a certain target profit margin on these volumes sold.

Litigation and Legal Items

From time to time, the Company is involved in various legal proceedings arising in the ordinary course of its business and reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the Company's best interests. The Company has provided the necessary estimated accruals in the condensed consolidated balance sheets where deemed appropriate for litigation and legal-related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, the Company currently believes that the ultimate results of such proceedings will not have a material adverse effect on our business, financial position, results of operations or liquidity.

Environmental. Due to the nature of the oil and natural gas industry, the Company is exposed to environmental liabilities in the ordinary course of its business. The Company has various policies and procedures in place to minimize and mitigate the risks from environmental contamination or with respect to environmental compliance issues. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as disclosed herein, the Company is not aware of any material environmental claims existing as of June 30, 2021 that have not been provided for or would otherwise have a material impact on the Company's financial statements. However, there can be no assurance that current regulatory requirements will not change or that unknown potential past non-compliance with environmental laws, compliance matters or other environmental liabilities will not be discovered on our properties. The liability ultimately incurred with respect to a matter may exceed the related accrual.

COGCC Notices of Alleged Violations (“NOAVs”). The Company previously received NOAVs from the Colorado Oil and Gas Conservation Commission (the “COGCC”) for alleged compliance violations. On July 27, 2021, the COGCC approved a global settlement agreement with the Company that resolves these NOAVs. The settlement agreement requires the Company to make a cash payment to the COGCC of $0.1 million and also contains an obligation that the Company complete pubic projects that will cost the Company approximately $0.5 million.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report contains "forward-looking statements." All statements, other than statements of historical facts, included or incorporated by reference herein concerning, among other things, the BCEI Merger and Crestone Peak Merger, any statements regarding the expected timetable for completing the BCEI Merger and Crestone Peak Merger, the results, effects, benefits and synergies of the BCEI Merger and Crestone Peak Merger, future opportunities for the combined company, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled or completed after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "'may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. For such statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- our ability to execute on our business strategy following emergence from bankruptcy;
- the COVID-19 pandemic, including its effects on commodity prices, downstream capacity, employee health and safety, business continuity and regulatory matters;
- federal and state regulations and laws;
- capital requirements and uncertainty of obtaining additional funding on terms acceptable to us;
- risks and restrictions related to our debt agreements;
- impact of political and regulatory developments in Colorado, particularly with respect to additional permit scrutiny;
- our ability to use derivative instruments to manage commodity price risk;
- realized oil, natural gas and NGL prices as well as the volatility and widening of differentials;
- a decline in oil, natural gas and NGL production, and the impact of general economic conditions on the demand for oil, natural gas and NGL and the availability of capital;
- asset impairments from commodity price declines;
- the willingness of the Organization of Petroleum Exporting Countries ("OPEC") to set and maintain production levels;
- unsuccessful drilling and completion activities and the possibility of resulting write-downs;
- geographical concentration of our operations;
- constraints in the DJ Basin of Colorado with respect to gathering, transportation and processing facilities and marketing;
- our ability to meet our proposed drilling schedule and to successfully drill wells that produce oil or natural gas in commercially viable quantities;
- seasonal weather conditions.
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- adverse variations from estimates of reserves, production, production prices and expenditure requirements, and our inability to replace our reserves through exploration and development activities;
- incorrect estimates associated with properties we acquire relating to estimated proved reserves, the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs of such acquired properties;
- drilling operations associated with the employment of horizontal drilling techniques, and adverse weather and environmental conditions;
- limited control over non-operated properties;
- title defects to our properties and inability to retain our leases;
- our ability to successfully develop our large inventory of undeveloped operated and non-operated acreage;
- our ability to retain key members of our senior management and key technical employees;
- cost of pending or future litigation;
- risks relating to managing our growth, particularly in connection with the BCEI Merger and Crestone Peak Merger and integration of other significant acquisitions;
- impact of environmental, health and safety, and other governmental regulations, and of current or pending legislation;
- changes in tax laws;
- effects of competition; and
- the outbreak of communicable diseases such as coronavirus.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas, and NGL that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers and management. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGL that are ultimately recovered.

In addition to the other information and risk factors set forth in this Quarterly Report, you should carefully consider the risk factors and other cautionary statements described under the heading "Risk Factors" included in Item 1A of this Quarterly Report, in the Company's Annual Report on Form 10-K for the year ended December 31, 2020
("Annual Report"), and in the Company's other filings with the Securities and Exchange Commission, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Quarterly Report. Except as required by law, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company's operating results. MD&A should be read in conjunction with the condensed consolidated financial statements and related notes included in Item 1 of this Quarterly Report. The following information updates the discussion of the Company's financial condition provided in its Annual Report and analyzes the changes in the results of operations between the three and combined six months ended June 30, 2021 and the three and six months ended June 30, 2020.

EXECUTIVE SUMMARY

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin of Colorado. We have developed an oil, natural gas and NGL asset base of proved reserves, as well as a portfolio of development drilling opportunities on high resource-potential leasehold on contiguous acreage blocks in some of the most productive areas of what we consider to be the core of the DJ Basin.

Financial Results

Our results of operations as reported in our condensed consolidated financial statements for the periods January 21, 2021 through June 30, 2021 (“Successor”), January 1, 2021 through January 20, 2021 (“Predecessor”), three months ended June 30, 2021 (“Successor”), and the three and six months ended June 30, 2020 (“Predecessor”) are in accordance with accounting principles generally accepted in the United States of America (“GAAP”). Although GAAP requires that we report on our results for the Successor and Predecessor periods separately, management views our operating results for the combined six months ended June 30, 2021 by combining the results of the Predecessor and Successor periods because management believes such presentation provides the most meaningful comparison of our results to prior periods. We are not able to compare the 20 days from January 1, 2021 through January 20, 2021 operating results to any of the previous periods reported in the condensed consolidated financial statements and do not believe reviewing this period in isolation would be useful in identifying any trends in or reaching any conclusions regarding our overall operating performance. We believe the key performance indicators such as operating revenues and expenses for the Successor period combined with the Predecessor period provide more meaningful comparisons to other periods and are useful in understanding operational trends. Additionally, there were no changes in policies between the periods and any material impacts as a result of fresh start reporting were included within the discussion of these changes. These combined results do not comply with GAAP and have not been prepared as pro forma results under applicable regulations, but are presented because we believe they provide the most meaningful comparison of our results to prior periods.

For the three and combined six months ended June 30, 2021, crude oil, natural gas and NGL sales, coupled with the impact of settled derivatives, increased to $204.4 million and $486.2 million, respectively, as compared to $94.5 million and $299.0 million, respectively, in the same prior year period due to an increase of $17.95 and $18.64, respectively, in realized price per BOE, including settled derivatives, partially offset by a decrease in sales volumes of approximately 1,347 MBoe and 3,480 MBoe, respectively.

For the three and combined six months ended June 30, 2021, we had net income of $24.5 million and $984.1 million, respectively, as compared to a net loss of $291.9 million and $282.9 million, respectively, for the three and six months ended June 30, 2020. The change to net income for the three months ended June 30, 2021 from a net loss for the three months ended June 30, 2020 was primarily driven by an increase in sales revenues of $160.5 million, a decrease in operating expenses of $122.2 million, a decrease in reorganization items, net of $26.9 million and a decrease of $18.1 million in interest expense, partially offset by an increase in income tax expenses of $4.8 million. The change to net income for the combined six months ended June 30, 2021 from a net loss for the six months ended June 30, 2020 was primarily driven by an increase in sales revenues of $287.8 million, a decrease in operating expenses of $307.4 million, an increase in reorganization items, net of $900.8 million, a decrease in the loss on deconsolidation of Elevation of $73.1 million and a decrease of $34.9 million in interest expense, partially offset by a decrease in commodity derivative gains of $310.6 million and an increase in income tax expenses of $25.9 million.

Adjusted EBITDAX was $150.1 million and $357.3 million, respectively, for the three and combined six months ended June 30, 2021 as compared to $114.0 million and $237.9 million, respectively, for the three and six months ended June 30, 2020, reflecting a 32% increase and 50% increase, respectively. Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please refer to “—Adjusted EBITDAX.”

Operational Results

During the three and combined six months ended June 30, 2021, we focused on improving free cash flow and implemented operational efficiencies to reduce drilling and completion costs. During the three months ended June 30, 2021, we incurred approximately $47.3 million in drilling 9 gross (6.4 net) wells with an average lateral length of 2.1 miles and completing 24 gross (14.9 net) wells with an average lateral length of 2.2 miles. In addition, we incurred approximately $3.4 million of leasehold and surface acreage additions. We turned 22 gross (16.3 net) wells to sales during the three months ended June 30, 2021.

During the combined six months ended June 30, 2021, we incurred approximately $78.8 million in drilling 20 gross (12.5 net) wells with an average lateral length of 2.2 miles and completing 39 gross (26.7 net) wells with an average lateral length of 2.2 miles, all of which were horizontal wells in the DJ Basin. In addition, we incurred approximately $4.6 million of leasehold and surface acreage additions. We turned 22 gross (16.3 net) wells to sales during the combined six months ended June 30, 2021.

Recent Developments

Emergence from Chapter 11 Bankruptcy

As previously disclosed, on June 14, 2020 (the "Petition Date"), Extraction and its wholly owned subsidiaries (collectively, the "Debtors"), filed voluntary petitions for relief under chapter 11 ("Chapter 11") of title 11 of the United States Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court"). The Debtors' Chapter 11 cases (the "Chapter 11 Cases") were jointly administered under the caption In *re Extraction Oil & Gas., et al.* Case No. 20-11548 (CSS).

On July 30, 2020, the Debtors filed a proposed Plan of Reorganization (as amended, modified, or supplemented from time to time, the "Plan") and related Disclosure Statement (as amended or modified, the "Disclosure Statement") describing the Plan and the solicitation of votes to approve the same from certain of the Debtors' creditors with respect to the Chapter 11 Cases. Subsequently on October 22, 2020 and November 5, 2020, the Debtors filed first and second amendments, respectively, to the Disclosure Statement. The hearing to consider approval of the Disclosure Statement was held on November 6, 2020. On November 6, 2020, the Bankruptcy Court approved the adequacy of the Disclosure Statement and the Debtors commenced a solicitation process to obtain votes on the Plan. The Plan was confirmed by order of the Bankruptcy Court on December 23, 2020 (the "Confirmation Order"). On January 20, 2021 (the "Emergence Date"), the Plan became effective in accordance with its terms and the Company emerged from the Chapter 11 Cases.

NASDAQ Delisting and Relisting

Our common stock was traded on the NASDAQ Global Select Market (the "NASDAQ") under the symbol "XOG" prior to June 25, 2020. On June 16, 2020, we received a letter from NASDAQ notifying us that in accordance with NASDAQ rules, our securities would be delisted at the opening of business on June 25, 2020. On June 25, 2020, our common stock began trading on the Pink Open Market under the symbol "XOGAQ". In connection with our emergence from the Chapter 11 Cases, our common stock was relisted on the NASDAQ on January 21, 2021 and began trading under the symbol "XOG."

Bonanza Creek Energy, Inc. Merger and Crestone Peak Merger

As previously disclosed, on May 9, 2021, Bonanza Creek Energy, Inc. ("Bonanza Creek") and Extraction signed a merger agreement (the "BCEI Merger Agreement") for an all-stock merger of equals (the "BCEI Merger"). On June 6, 2021, Extraction entered into a merger agreement, by and among Bonanza Creek, Raptor Condor Merger Sub 1, Inc., a Delaware corporation and a wholly owned subsidiary of BCEI, Raptor Condor Merger Sub 2, LLC, a Delaware limited liability company and a wholly owned subsidiary of BCEI, Crestone Peak Resources LP, a Delaware limited partnership, CPPIB Crestone Peak Resources America Inc., a Delaware corporation ("Crestone Peak"), Crestone Peak Resources Management LP, a Delaware limited partnership (the "Crestone Peak Merger Agreement"). The Crestone Peak Merger Agreement, among other things, provides for Bonanza Creek's acquisition of Crestone Peak (the "Crestone Peak Merger"). The closing of the Crestone Peak Merger is expressly conditioned on the closing of the BCEI Merger. Upon completion of the BCEI Merger and Crestone Peak Merger, the combined company will be named Civitas Resources, Inc. ("Civitas"). Following the BCEI Merger and Crestone Peak Merger, Bonanza Creek President and Chief Executive Officer, Eric Greager, will serve as President and CEO of Civitas. Other senior leadership positions will be filled by current executives of Bonanza Creek and Extraction. As designated in the BCEI Merger agreement, of the six named officers, three will be from Bonanza Creek and three from Extraction. Extraction Chairman of the Board of Directors ("Board"), Ben Dell, will serve as Chairman of Civitas, and Bonanza Creek and Extraction will each nominate four directors, and CPP Investments will nominate one director to Civitas' diverse, nine-member Board. We anticipate the BCEI Merger will be completed during the latter half of 2021.

Divestiture

In April 2021, we completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $15.2 million, subject to customary purchase price adjustments. No gain or loss was recognized. In conjunction with the April 2021 divestiture,we recorded a receivable of approximately $2.7 million in the condensed consolidated balance sheet as of June 30, 2021 for post-closing adjustments.

How We Evaluate Our Operations

We use various financial and operational metrics to assess the performance of our operations, including:

- Sources of revenue;
- Sales volumes;
- Realized prices on the sale of oil, natural gas and NGL, including the effect of our commodity derivative contracts;
- Lease operating expenses;
- Capital expenditures;
- Adjusted EBITDAX (a non-GAAP measure);
- Free cash flow (a non-GAAP measure); and
- Combined Predecessor period January 1, 2021 to January 20, 2021 and Successor period January 21, 2021 to June 30, 2021 (a non-GAAP measure) for comparison purposes in MD&A.

Sources of Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives. For the three months ended June 30, 2021, our revenues were derived 62% from oil sales, 18% from natural gas sales and 20% from NGL sales. For the three months ended June 30, 2020, our revenues were derived 58% from oil sales, 25% from natural gas sales and 17% from NGL sales. For the combined six months ended June 30, 2021, our revenues were derived 52% from oil sales, 32% from natural gas sales and 16% from NGL sales. For the six months ended June 30, 2020, our revenues were derived 71% from oil sales, 17% from natural gas sales and 12% from NGL sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Sales Volumes

The following table presents historical sales volumes for the periods indicated:

	Successor	Predecessor
	For the Three Months Ended June 30,	For the Three Months Ended June 30,
	2021	2020
Oil (MBbl)	2,349	3,419
Natural gas (MMcf)	15,834	17,543
NGL (MBbl)	1,987	1,979
Total (MBoe)	6,975	8,322
Average net sales (BOE/d)	76,645	91,451

	Successor	Predecessor	Non-GAAP	Predecessor
	For the Period from January 21 through June 30,	For the Period from January 1 through January 20,	Combined Six Months Ended June 30,	For the Six Months Ended June 30,
	2021	2021	2021	2020
Oil (MBbl)	4,141	546	4,687	6,923
Natural gas (MMcf)	27,198	3,412	30,610	36,546
NGL (MBbl)	3,254	376	3,630	3,885
Total (MBoe)	11,927	1,492	13,419	16,899
Average net sales (BOE/d)	74,081	74,600	74,137	92,852

As reservoir pressures decline, production from a given well or formation decreases. Growth or maintenance in our future production and reserves will depend on our ability to continue to add or develop proved reserves in excess of our production. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including takeaway capacity in our areas of operation and our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please refer to “Risks Related to the Oil, Natural Gas and NGL Industry and Our Business” in Item 1A of the Company’s Annual Report for a further description of the risks that affect us.

Realized Prices on the Sale of Oil, Natural Gas and NGL

Our results of operations depend upon many factors, particularly the price of oil, natural gas and NGL and our ability to market our production effectively. Oil, natural gas and NGL prices are among the most volatile of all commodity prices. For example, during the period from January 1, 2019 to June 30, 2021, NYMEX West Texas Intermediate (“WTI”) oil prices ranged from a high of $74.05 per Bbl to a low of negative $37.63 per Bbl. NYMEX Henry Hub gas prices ranged from a high of $3.65 per MMBtu to a low of $1.48 per MMBtu during the same period. Fluctuations in the price of oil and natural gas occurring during 2019, 2020 and 2021 are due to a combination of factors including increased U.S. supply, global economic concerns stemming from COVID-19, the price war between Russia and OPEC+, and the 2021 Texas Power crisis. These price fluctuations can have a material impact on our financial results and capital expenditures.

Oil pricing is predominantly driven by fluctuations in supply and demand, including as a result of production and storage capacity, financial markets, and geopolitical factors. The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. In the DJ Basin, oil is sold under various purchase contracts with monthly pricing provisions based on NYMEX pricing, adjusted for differentials.

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to dry natural gas with a low Btu content because it yields a greater quantity of NGL. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant, generally in the form of percentage of proceeds. The price we receive for our natural gas produced in the DJ Basin is based on CIG prices, adjusted for certain deductions.

Our price for NGL produced in the DJ Basin is based on a combination of prices from Mont Belvieu in Texas and the Conway hub in Kansas where this production is marketed.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. The differential varies, but our oil, natural gas and NGLs normally sell at a discount to the NYMEX WTI and NYMEX Henry Hub price, as applicable.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2021	2020	2021	2020
Oil				
NYMEX WTI High ($/Bbl)	$ 74.05	$ 40.46	$ 74.05	$ 63.27
NYMEX WTI Low ($/Bbl)	$ 58.65	$ (37.63)	$ 47.62	$ (37.63)
NYMEX WTI Average ($/Bbl)	$ 66.10	$ 28.00	$ 62.21	$ 36.82
Average Realized Price ($/Bbl)(1)	$ 59.22	$ 10.61	$ 56.92	$ 23.18
Average Realized Price, with derivative settlements ($/Bbl)(1)	$ 50.60	$ 18.11	$ 50.27	$ 31.97
Average Realized Price as a % of Average NYMEX WTI	89.6 %	37.9 %	91.5 %	63.0 %
Differential ($/Bbl) to Average NYMEX WTI(2)(3)	$ (6.88)	$ (16.26)	$ (5.29)	$ (11.85)
Natural Gas				
NYMEX Henry Hub High ($/MMBtu)	$ 3.65	$ 2.13	$ 3.65	$ 2.20
NYMEX Henry Hub Low ($/MMBtu)	$ 2.46	$ 1.48	$ 2.45	$ 1.48
NYMEX Henry Hub Average ($/MMBtu)	$ 2.97	$ 1.75	$ 2.85	$ 1.81
NYMEX Henry Hub Average converted to a $/Mcf basis(4)	$ 3.27	$ 1.93	$ 3.14	$ 1.99
Average Realized Price ($/Mcf)(5)	$ 2.49	$ 0.91	$ 5.38	$ 1.05
Average Realized Price, with derivative settlements ($/Mcf)(5)	$ 2.56	$ 1.24	$ 5.42	$ 1.32
Average Realized Price as a % of Average NYMEX Henry Hub(4)(5)	76.1 %	47.2 %	171.3 %	52.8 %
Differential ($/Mcf) to Average NYMEX Henry Hub(4)(5)	$ (0.78)	$ (1.02)	$ 2.24	$ (0.94)
NGL				
Average Realized Price ($/Bbl)(5)	$ 22.67	$ 5.47	$ 23.33	$ 7.21
Average Realized Price as a % of Average NYMEX WTI(5)	34.3 %	19.5 %	37.5 %	19.6 %
BOE				
Average Realized Price per BOE(1)	$ 32.06	$ 7.59	$ 38.46	$ 13.42
Average Realized Price per BOE with derivative settlements	$ 29.30	$ 11.35	$ 36.24	$ 17.60

(1) Includes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the three and six months ended June 30, 2020, pursuant to ASC *Topic 606—Revenue Recognition* ("ASC 606").
(2) Excludes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the three and six months ended June 30, 2020, pursuant to ASC 606.
(3) During the first quarter of 2021, our renegotiated crude oil midstream contract was effective as of March 1, 2021, which resulted in a change in the accounting treatment under ASC 606. As a result, the crude oil differential for the combined six months ended June 30, 2021 is not reflective of our differential going forward.
(4) Based on the difference between our average realized price and the NYMEX Henry Hub Average as converted into Mcf using a conversion factor of 1.1 to 1.
(5) During the first quarter of 2021, a large portion of our gas and NGL contracts were subject to daily prices versus a monthly average price. As a result, our realized prices for the combined six months ended June 30, 2021 benefited from several days of severe cold during February 2021.

Derivative Arrangements

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time, we enter into derivative arrangements for our oil and natural gas production. By removing a significant portion of price volatility associated with our oil and natural gas production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil and natural gas prices on our cash flow from operations for those periods. However, in a portion of our current positions, our hedging activity may also reduce our ability to benefit from increases in oil and natural gas prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will realize gains to the extent our derivatives contract prices are higher than market prices. In certain circumstances, we may choose to restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. We have relied on a variety of hedging strategies and instruments to hedge our future price risk. We have utilized swaps, put options and call options, which in some instances require the payment of a premium, to reduce the effect of price changes on a portion of our future oil and natural gas production. We expect to continue to use a variety of hedging strategies and instruments for the foreseeable future. The RBL Credit Agreement requires us to maintain commodity hedges covering a minimum of 65% of our anticipated oil and gas production from PDP reserves for the succeeding twelve months and 50% of our anticipated oil and gas production from PDP reserves for the next succeeding twelve months.

The hedge prices will depend on the commodity price environment at the time at which those hedge transactions are entered. In the current commodity price environment, our ability to enter into derivative arrangements at favorable prices may be limited.

For a description of our derivative instruments that we utilize and a summary of our commodity derivative contracts as of June 30, 2021, please see *Note 5—Commodity Derivative Instruments* in Item 1 of this Quarterly Report.

The following table summarizes our historical derivative positions and the settlement amounts for each of the periods indicated:

	Successor For the Period from January 21 through June 30, 2021	Predecessor For the Period from January 1 through January 20, 2021	Predecessor For the Six Months Ended June 30, 2020
NYMEX WTI Crude Swaps:			
Notional volume (Bbl)	2,788,200	—	525,000
Weighted average fixed price ($/Bbl)	$ 50.34	$ —	$ 60.05
NYMEX WTI Crude Purchased Puts:			
Notional volume (Bbl)	—	—	4,950,000
Weighted average purchased put price ($/Bbl)	$ —	$ —	$ 54.48
NYMEX WTI Crude Purchased Calls:			
Notional volume (Bbl)	—	—	1,100,000
Weighted average purchased call price ($/Bbl)	$ —	$ —	$ 68.04
NYMEX WTI Crude Sold Calls:			
Notional volume (Bbl)	—	—	5,650,000
Weighted average sold call price ($/Bbl)	$ —	$ —	$ 63.37
NYMEX WTI Crude Sold Puts:			
Notional volume (Bbl)	—	—	5,300,000
Weighted average sold put price ($/Bbl)	$ —	$ —	$ 44.39
NYMEX HH Natural Gas Swaps:			
Notional volume (MMBtu)	12,437,315	—	17,400,000
Weighted average fixed price ($/MMBtu)	$ 2.94	$ —	$ 2.75
NYMEX HH Natural Gas Purchased Puts:			
Notional volume (MMBtu)	—	—	600,000
Weighted average purchased put price ($/MMBtu)	$ —	$ —	$ 2.90
NYMEX HH Natural Gas Sold Calls:			
Notional volume (MMBtu)	—	—	600,000
Weighted average sold call price ($/MMBtu)	$ —	$ —	$ 3.48
CIG Basis Gas Swaps:			
Notional volume (MMBtu)	—	—	22,800,000
Weighted average fixed basis price ($/MMBtu)	$ —	$ —	$ (0.61)
Total Amounts Received/(Paid) from Settlement (in thousands)	$ (29,871)	$ —	$ 166,725
Cash provided by (used in) changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	8,703	542	(5,213)
Derivative unwinds reducing the Prior Credit Facility balance	—	—	(96,065)
Settlements on Commodity Derivatives per Condensed Consolidated Statements of Cash Flows	$ (21,168)	$ 542	$ 65,447

Lease Operating Expenses

All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constitutes part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, water injection and disposal costs, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses.

Capital Expenditures

For the combined six months ended June 30, 2021, we incurred approximately $78.8 million in drilling and completion capital expenditures. For the combined six months ended June 30, 2021, we drilled 20 gross (12.5 net) wells with an average lateral length of approximately 2.2 miles and completed 39 gross (26.7 net) wells with an average lateral length of approximately 2.2 miles. We turned to sales 22 gross (16.3 net) wells with an average lateral length of approximately 2.2 miles during the combined six months ended June 30, 2021. In addition, we incurred approximately $4.6 million of leasehold and surface acreage additions during the combined six months ended June 30, 2021.

On July 8, 2021, the board of directors approved an increase in our 2021 capital expenditures budget. The 2021 total revised capital budget was approved to be $159 million, which includes $146 million for drilling and completion activity and $13 million for plugging and abandoning and other activity. Previously, our 2021 capital budget was $142 million, which included $130 million for drilling and completions activity and $12 million for plugging and abandoning and other activity.

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income (loss) as determined by GAAP. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items shown in the table below, which presents a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income (loss) for each of the periods indicated (in thousands).

	Successor	Predecessor
	For the Three Months Ended June 30,	For the Three Months Ended June 30,
	2021	2020
Reconciliation of Net Income (Loss) to Adjusted EBITDAX:		
Net income (loss)	$ 24,544	$ (291,934)
Add back:		
Depletion, depreciation, amortization and accretion	50,090	82,620
Impairment of long-lived assets	170	960
Other operating expenses	5,380	13,209
Exploration and abandonment expenses	3,586	62,661
Loss on commodity derivatives	75,839	69,301
Settlements on commodity derivative instruments	(19,237)	127,429
Stock-based compensation expense	2,771	2,560
Amortization of debt issuance costs	457	1,948
Interest expense	1,713	18,366
Income tax expense	4,775	—
Reorganization items, net	—	26,919
Adjusted EBITDAX	$ 150,088	$ 114,039

	Successor	Predecessor	Non-GAAP	Predecessor
	For the Period from January 21 through June 30,	For the Period from January 1 through January 20,	Combined Six Months Ended June 30,	For the Six Months Ended June 30,
	2021	2021	2021	2020
Reconciliation of Net Income (Loss) to Adjusted EBITDAX:				
Net income (loss)	$ 113,098	$ 870,970	$ 984,068	$ (282,897)
Add back:				
Depletion, depreciation, amortization and accretion	88,665	16,133	104,798	158,670
Impairment of long-lived assets	170	—	170	1,736
Other operating expenses	9,262	1,107	10,369	65,784
Exploration and abandonment expenses	4,345	316	4,661	175,141
(Gain) loss on commodity derivatives	104,325	12,586	116,911	(193,714)
Settlements on commodity derivative instruments	(29,871)	—	(29,871)	166,725
Stock-based compensation expense	4,945	302	5,247	2,560
Amortization of debt issuance costs	909	113	1,022	3,190
Interest expense	4,294	1,421	5,715	38,482
Income tax expense	28,100	—	28,100	2,200
Loss on deconsolidation of Elevation Midstream, LLC	—	—	—	73,139
Reorganization items, net	—	(873,908)	(873,908)	26,919
Adjusted EBITDAX	$ 328,242	$ 29,040	$ 357,282	$ 237,935

Management believes Adjusted EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed in the table above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital, hedging strategy and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance. Additionally, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

(i) is widely used by investors in the oil and natural gas industry to measure a company’s operating performance without regard to items excluded from the calculation of such term, among other factors;

(ii) helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

(iii) is used by our management team for various purposes, including as a measure of operating performance, in presentations to our Board, as a basis for strategic planning and forecasting.

Free Cash Flow

Our Free Cash Flow is not a measure of and should not be considered an alternative to, or more meaningful than, net income (loss) as determined by GAAP. We define Free Cash Flow as Discretionary Cash Flow (non-GAAP) less Adjusted Cash Flow used in Investing (non-GAAP) adjusted for Other Non-Recurring Adjustments (non-GAAP). Discretionary Cash Flow is defined as net cash provided by operating activities (GAAP) before changes in working capital accounts (current assets and liabilities). Adjusted Cash Flow used in Investing is defined as cash flow used in investing activities (GAAP) adjusted for changes in accounts payable and accrued liabilities related to capital expenditures.

Free Cash Flow is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Free Cash Flow can provide additional transparency into the drivers of trends in our operating cash flows, such as production, realized sales prices and operating costs, as it disregards the timing of settlement of operating assets and liabilities. We believe Free Cash Flow provides additional information that may be useful in an analysis of our ability to generate cash to fund exploration and development activities and to return capital to stockholders.

The following tables present a reconciliation of Discretionary Cash Flow and Free Cash Flow to the GAAP financial measure of net cash provided by operating activities for each of the periods indicated.

	Successor	Predecessor
	For the Three Months Ended June 30, 2021	For the Three Months Ended June 30, 2020
Cash Flow from Operating Activities		
Net cash used in operating activities	$ (7,339)	$ (63,145)
Changes in current assets and liabilities	148,709	52,983
Discretionary Cash Flow	141,370	(10,162)
Cash Flow from Investing Activities		
Net cash used in investing activities	(18,474)	(51,710)
Change in accounts payable and accrued liabilities related to capital expenditures	(15,544)	34,851
Adjusted Cash Flow used in Investing	(34,018)	(16,859)
Free Cash Flow	$ 107,352	$ (27,021)

	Successor	Predecessor	Non-GAAP
	For the Period from January 21 through June 30, 2021	For the Period from January 1 through January 20, 2021	Combined Six Months Ended June 30, 2021
Cash Flow from Operating Activities			
Net cash provided by operating activities	$ 141,769	$ 15,346	$ 157,115
Changes in current assets and liabilities	155,481	(17,089)	138,392
Discretionary Cash Flow	297,250	(1,743)	295,507
Cash Flow from Investing Activities			
Net cash used in investing activities	(41,173)	(9,120)	(50,293)
Change in accounts payable and accrued liabilities related to capital expenditures	(16,416)	(1,442)	(17,858)
Adjusted Cash Flow used in Investing	(57,589)	(10,562)	(68,151)
Free Cash Flow	$ 239,661	$ (12,305)	$ 227,356

	Predecessor		
	Upstream	Midstream	Consolidated
	For the Six Months Ended June 30, 2020		
Cash Flow from Operating Activities			
Net cash provided by operating activities	$ 81,074	$ 2,880	$ 83,954
Changes in current assets and liabilities	(48,064)	(1,907)	(49,971)
Discretionary Cash Flow	33,010	973	33,983
Cash Flow from Investing Activities			
Net cash used in investing activities	(185,573)	(5,840)	(191,413)
Change in accounts payable and accrued liabilities related to capital expenditures	24,374	2,210	26,584
Adjusted Cash Flow used in Investing	(161,199)	(3,630)	(164,829)
Other Non-Recurring Adjustments[1]	1,170	—	1,170
Free Cash Flow	$ (127,019)	$ (2,657)	$ (129,676)

(1) Amount incurred for the construction of our field office that is included in other property and equipment in our condensed consolidated statements of cash flows.

Items Affecting the Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, for the reasons described below:

- Upon emerging from bankruptcy on January 20, 2021, we recorded our consolidated balance sheet accounts at fair value. See *Note 3—Fresh Start Reporting* in Item 1 of this Quarterly Report. Now, the Successor period January 21, 2021 to June 30, 2021 is not comparable to the Predecessor period from January 1, 2021 to January 20, 2021 and in relation to the first six months of 2020. We illustrate this lack of comparability by using a black line in tables to separate Predecessor Company amounts from Successor Company amounts. We overcome this lack of comparability by combining the Predecessor and Successor periods so they can be viewed in relation to the first six months of 2020.
- During the Chapter 11 Cases, our financial results were volatile as restructuring activities and expenses, contract terminations and rejections, and claims assessments significantly impacted our financial results. For the combined six months ended June 30, 2021, prior to emergence, we realized an $873.9 million reorganization items, net gain. As a result, our historical financial performance is likely not indicative of financial performance after the date of the bankruptcy filing. Despite the Company's emergence from the Chapter 11 Cases, claim assessments will continue for the foreseeable future.
- For the combined six months ended June 30, 2021 compared to the six months ended June 30, 2020, exploration and abandonment expenses decreased primarily due to the abandonment of $169.6 million in unproved properties during the six months ended June 30, 2020. Abandoned properties for the combined six months ended June 30, 2021 were $2.4 million. During the first quarter of 2021 we emerged from bankruptcy where we revalued our oil and gas properties. See *Note 3—Fresh Start Reporting* in Item 1 of this Quarterly Report for information related to our asset and liability values upon emergence.
- Elevation Midstream, LLC was deconsolidated as of March 16, 2020 and accounted for as an equity method investment. We elected the fair value option to remeasure the Elevation Midstream, LLC equity method investment and determined it had no fair value. We recorded a $73.1 million loss on deconsolidation of Elevation Midstream, LLC in the condensed consolidated statements of operations for the six months ended June 30, 2020.

Historical Results of Operations and Operating Expenses

Oil, Natural Gas and NGL Sales Revenues, Operating Expenses and Other Income (Expense).

For components of our revenues, operating expenses, other income (expense) and net income (loss), please see our condensed consolidated statements of operations in Item 1 of this Quarterly Report.

The following table provides a summary of our sales volumes, average prices and operating expenses on a per BOE basis for the periods indicated:

	Successor	Predecessor
	For the Three Months Ended June 30,	For the Three Months Ended June 30,
	2021	2020
Sales (MBoe)[1]:	6,975	8,322
Oil sales (MBbl)	2,349	3,419
Natural gas sales (MMcf)	15,834	17,543
NGL sales (MBbl)	1,987	1,979
Sales (BOE/d)[1]:	76,645	91,451
Oil sales (Bbl/d)	25,814	37,571
Natural gas sales (Mcf/d)	173,997	192,780
NGL sales (Bbl/d)	21,829	21,747
Average sales prices[2]:		
Oil sales (per Bbl)[3]	$ 59.22	$ 10.61
Oil sales with derivative settlements (per Bbl)[3]	50.60	18.11
Natural gas sales (per Mcf)[4]	2.49	0.91
Natural gas sales with derivative settlements (Mcf)[4]	2.56	1.24
NGL sales (per Bbl)[4]	22.67	5.47
Average price (per BOE)[4][3]	32.06	7.59
Average price with derivative settlements (per BOE)[4][3]	29.30	11.35
Expense per BOE:		
Lease operating expenses	$ 1.97	$ 2.76
Transportation and gathering	3.09	3.16
Production taxes	1.56	0.56
Exploration and abandonment expenses	0.51	7.53
Depletion, depreciation, amortization and accretion	7.18	9.93
General and administrative expenses	1.57	3.02
Cash general and administrative expenses[5]	1.17	2.71
Stock-based compensation	0.40	0.31
Total operating expenses per BOE[6]	$ 15.88	$ 26.96
Production taxes as a percentage of revenue[7]	4.9 %	7.4 %

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.
(2) Average prices shown in the table reflect prices both before and after the effects of our settlements of our commodity derivative contracts. Our calculation of such effects includes both gains and losses on settlements for commodity derivatives on swaps that settled during the period.
(3) Includes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the Predecessor three months ended June 30, 2020, pursuant to ASC 606.
(4) During the first quarter of 2021, a large portion of our gas and NGL contracts were subject to daily prices versus a monthly average price. As a result, our realized prices benefited from several days of severe cold during February 2021.
(5) Cash general and administrative expenses for the Predecessor three months ended June 30, 2020 includes expense of $0.3 million related to the terms of a separation agreement with one former executive officer. Excluding this one-time expense results in cash general and administrative expense per BOE of $2.68 for the Predecessor three months ended June 30, 2020.
(6) Excludes impairment of long-lived assets and other operating expenses.
(7) Production taxes as percentage of revenue during the Successor three months ended June 30, 2021 is lower than the rate that can be expected going forward due to a true up of ad valorem taxes pursuant to a reduction in estimated rates.

	Successor	Predecessor	Non-GAAP	Predecessor
	For the Period from January 21 through June 30,	For the Period from January 1 through January 20,	For the Combined Six Months Ended June 30,	For the Six Months Ended June 30,
	2021	2021	2021	2020
Sales (MBoe)[1]:	11,927	1,492	13,419	16,899
Oil sales (MBbl)	4,141	546	4,687	6,923
Natural gas sales (MMcf)	27,198	3,412	30,610	36,546
NGL sales (MBbl)	3,254	376	3,630	3,885
Sales (BOE/d)[1]:	74,081	74,600	74,137	92,852
Oil sales (Bbl/d)	25,719	27,312	25,895	38,038
Natural gas sales (Mcf/d)	168,933	170,588	169,113	200,802
NGL sales (Bbl/d)	20,209	18,820	20,049	21,346
Average sales prices[2]:				
Oil sales (per Bbl)[3]	$ 57.88	$ 49.68	$ 56.92	$ 23.18
Oil sales with derivative settlements (per Bbl)[3]	50.35	49.68	50.27	31.97
Natural gas sales (per Mcf)[4]	5.77	2.29	5.38	1.05
Natural gas sales with derivative settlements (Mcf)[4]	5.81	2.29	5.42	1.32
NGL sales (per Bbl)[4]	23.55	21.52	23.33	7.21
Average price (per BOE)[4][3]	39.66	28.85	38.46	13.42
Average price with derivative settlements (per BOE)[4][3]	37.16	28.85	36.24	17.60
Expense per BOE:				
Lease operating expenses	$ 2.05	$ 1.71	$ 2.01	$ 3.16
Transportation and gathering	3.75	4.19	3.80	2.91
Production taxes	2.71	2.21	2.66	1.07
Exploration and abandonment expenses	0.36	0.21	0.35	10.36
Depletion, depreciation, amortization and accretion	7.43	10.81	7.81	9.39
General and administrative expenses	1.55	1.48	1.54	2.12
Cash general and administrative expenses[5]	1.14	1.28	1.15	1.97
Stock-based compensation	0.41	0.20	0.39	0.15
Total operating expenses per BOE[6]	$ 17.85	$ 20.61	$ 18.17	$ 29.01
Production taxes as a percentage of revenue	6.8 %	7.7 %	6.9 %	7.9 %

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.
(2) Average prices shown in the table reflect prices both before and after the effects of our settlements of our commodity derivative contracts. Our calculation of such effects includes both gains and losses on settlements for commodity derivatives on swaps that settled during the period.
(3) Includes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the Predecessor six months ended June 30, 2020, pursuant to ASC 606.
(4) During the first quarter of 2021, a large portion of our gas and NGL contracts were subject to daily prices versus a monthly average price. As a result, our realized prices benefited from several days of severe cold during February 2021.
(5) Cash general and administrative expenses for the Predecessor six months ended June 30, 2020 includes expense of $2.5 million related to the terms of a separation agreement with two former executive officers. Excluding this one-time expense results in cash general and administrative expense per BOE of $1.82 for the Predecessor six months ended June 30, 2020.
(6) Excludes impairment of long-lived assets and other operating expenses.

Three Months Ended June 30, 2021 Compared to Three Months Ended June 30, 2020

Oil sales revenues. Crude oil sales revenues increased by $102.8 million to $139.1 million for the three months ended June 30, 2021 as compared to crude oil sales of $36.3 million for the three months ended June 30, 2020. An increase in crude oil prices contributed a $114.2 million positive impact, and a decrease in sales volumes between these periods contributed a $11.4 million negative impact. For the three months ended June 30, 2020, crude oil revenue decreased by approximately $3.9 million due to the impact of the increase in the forecasted deferral balance on one of our revenue contracts. Pursuant to ASC 606, the contract term impacts the amount of consideration that could be included in the transaction price, which reduced oil sales revenue.

For the three months ended June 30, 2021, our crude oil sales averaged 25.8 MBbl/d. Our crude oil sales volume decreased by 1,070 to 2,349 MBbl for the three months ended June 30, 2021 compared to 3,419 MBbl for the three months ended June 30, 2020. The volume decrease is primarily due to the natural decline of our existing properties, only partially offset by an increase in production from the completion of 40 gross wells from July 1, 2020 to June 30, 2021, since during the second half of 2020 and in early 2021 prior to emergence from bankruptcy, our drilling program had been suspended.

The average price we realized on the sale of crude oil was $59.22 per Bbl for the three months ended June 30, 2021 compared to $10.61 per Bbl for the three months ended June 30, 2020. For the three months ended June 30, 2020, crude oil revenue decreased $3.9 million due to the contract term impacting the amount of consideration that can be included in the transaction price, which reduced oil sales revenue pursuant to ASC 606. For the three months ended June 30, 2021, no such decrease in crude oil revenue was recorded.

Natural gas sales revenues. Natural gas sales revenues increased by $23.5 million to $39.5 million for the three months ended June 30, 2021 as compared to natural gas sales revenues of $16.0 million for the three months ended June 30, 2020. An increase in natural gas prices contributed a $25.1 million positive impact, while a decrease in sales volumes between these periods contributed a $1.6 million negative impact.

For the three months ended June 30, 2021, our natural gas sales averaged 174.0 MMcf/d. Natural gas sales volumes decreased by 1,709 to 15,834 MMcf for the three months ended June 30, 2021 as compared to 17,543 MMcf for the three months ended June 30, 2020. The volume decrease is primarily due to the natural decline on existing producing properties, partially offset by the completion of 40 gross wells from July 1, 2020 to June 30, 2021, since during the second half of 2020 and in early 2021 prior to emergence from bankruptcy, our drilling program had been suspended.

The average price we realized on the sale of our natural gas was $2.49 per Mcf for the three months ended June 30, 2021 compared to $0.91 per Mcf for the three months ended June 30, 2020, primarily due to an increase in pricing as compared to the three months ending June 30, 2020.

NGL sales revenues. NGL sales revenues increased by $34.2 million to $45.0 million for the three months ended June 30, 2021 as compared to NGL sales revenues of $10.8 million for the three months ended June 30, 2020. An increase in prices between these periods contributed a $34.2 million positive impact, while a decrease in volumes contributed an immaterial negative impact.

For the three months ended June 30, 2021, our NGL sales averaged 21.8 MBbl/d. NGL sales volumes increased by 8 to 1,987 MBbl for the three months ended June 30, 2021 as compared to 1,979 MBbl for the three months ended June 30, 2020. The volume increase is primarily due to the completion of 40 gross wells from July 1, 2020 to June 30, 2021, partially offset by the natural decline on existing producing properties. Our NGL sales are directly associated with our natural gas sales because our natural gas volumes are processed by third parties for both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $22.67 per Bbl for the three months ended June 30, 2021 compared to $5.47 per Bbl for the three months ended June 30, 2020, primarily due to an increase in pricing as compared to the three months ending June 30, 2020.

Lease operating expenses ("LOE"). Our LOE decreased by $9.3 million to $13.7 million for the three months ended June 30, 2021, from $23.0 million for the three months ended June 30, 2020. While oil revenue increased for the three months ended June 30, 2021, oil volumes were down for the reasons mentioned above. This allowed the company to optimize our field cost structure during the three months ended June 30, 2021. On a per unit basis, LOE decreased to $1.97 per BOE sold for the three months ended June 30, 2021 from $2.76 per BOE for the three months ended June 30, 2020.

Transportation and gathering ("T&G"). Our T&G expense decreased by $4.7 million to $21.6 million for the three months ended June 30, 2021, from $26.3 million for the three months ended June 30, 2020. The decrease in T&G was primarily due to revenue contract changes and a decrease in production during the three months ended June 30, 2021 compared to the three months ended June 30, 2020. On a per unit basis, T&G decreased to $3.09 per BOE sold for the three months ended June 30, 2021 compared to $3.16 per BOE sold for the three months ended June 30, 2020.

Production taxes. Our production taxes increased by $6.2 million to $10.9 million for the three months ended June 30, 2021 as compared to $4.7 million for the three months ended June 30, 2020. The increase is primarily attributable to increased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue were 4.9% for the three months ended June 30, 2021 as compared to 7.4% for the three months ended June 30, 2020.

Exploration and abandonment expenses. Our exploration and abandonment expenses were $3.6 million for the three months ended June 30, 2021. For the three months ended June 30, 2020, we recognized $62.7 million in exploration and abandonment expenses. The decrease in abandonment expense during 2021 was because our assets were fair valued upon emergence from bankruptcy on January 20, 2021.

Depletion, depreciation, amortization and accretion expense ("DD&A"). Our DD&A expense decreased $32.5 million to $50.1 million for the three months ended June 30, 2021 as compared to $82.6 million for the three months ended June 30, 2020. On a per unit basis, DD&A expense decreased to $7.18 per BOE for the three months ended June 30, 2021 from $9.93 per BOE for the three months ended June 30, 2020. These decreases are due to the $326.0 million downward fair value adjustment to the depletable asset base upon adoption of fresh start reporting, as well as an impairment of $208.5 million of proved oil and gas properties that occurred during 2020.

General and administrative expenses ("G&A"). General and administrative expenses decreased by $14.2 million to $10.9 million for the three months ended June 30, 2021 as compared to $25.1 million for the three months ended June 30, 2020. This decrease is primarily due to reductions of workforce during 2020 and a decrease in pre-petition advisory fees recognized for the three months ended June 30, 2020 compared to the three months ended June 30, 2021. On a per unit basis, G&A expense decreased to $1.57 per BOE sold for the three months ended June 30, 2021 from $3.02 per BOE sold for the three months ended June 30, 2020.

Our G&A expenses for the three months ended June 30, 2020 includes $0.3 million related to the terms of a separation agreement with a former executive officer. No expenses of this nature were incurred during the three months ended June 30, 2021.

Our G&A expenses include the non-cash expense for stock-based compensation for equity awards granted to our employees and directors. For the three months ended June 30, 2021, there was $2.8 million of stock-based compensation expense. For the three months ended June 30, 2020, stock-based compensation expense was $2.6 million.

Other operating expenses. Other operating expenses decreased by $7.8 million to $5.4 million for the three months ended June 30, 2021 as compared to $13.2 million for the three months ended June 30, 2020. This decrease is due primarily to non-recurring early termination penalties of $11.9 million, which includes a $9.5 million early termination fee related to the termination of our crude oil marketing contract and a $2.4 million rig termination fee. The decrease is also due to a $2.2 million reduction of restructuring expenses from period to period. These decreases were partially offset by an increase in merger and acquisition costs of $6.6 million.

Commodity derivative loss. Primarily due to the increase in NYMEX crude oil future prices at June 30, 2021 as compared to March 31, 2021 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $75.8 million for the three months ended June 30, 2021. Primarily due to the increase in NYMEX crude oil futures prices at June 30, 2020 as compared to March 31, 2020 and change in fair value from the execution and unwinds of hedged positions, we incurred a net loss on our commodity derivatives of $69.3 million for the three months ended June 30, 2020. These losses are a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program in the future. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the three months ended June 30, 2021, we paid commodity derivatives totaling $19.2 million. During the three months ended June 30, 2020, we received settlements of commodity derivatives totaling $127.4 million.

Reorganization items, net. Due to the commencement of the Chapter 11 Cases during the second quarter of 2020, we have incurred significant costs associated with our reorganization, primarily from damages for rejected or settled contracts and legal and professional fees. For the three months ended June 30, 2020, we recognized $26.9 million of reorganization items, net due to the Company entering into bankruptcy proceedings. No reorganization gain or loss was recognized during the three months ended June 30, 2021.

Interest expense. Interest expense consists of interest expense on our long-term debt and amortization of debt issuance costs, net of capitalized interest. For the three months ended June 30, 2021, we recognized interest expense of $2.2 million as compared to $20.3 million for the three months ended June 30, 2020. Upon filing its petition for Chapter 11, we ceased accruing interest expense on our 2024 and 2026 Senior Notes. We had outstanding debt of $90.0 million as of June 30, 2021.

We incurred interest expense for the three months ended June 30, 2021 of $1.8 million related to our RBL Credit Facility. We incurred interest expense for the three months ended June 30, 2020 of approximately $20.2 million related to our Prior Credit Facility, DIP Credit Facility, our 2024 Senior Notes, and our 2026 Senior Notes. Also included in interest expense for the three months ended June 30, 2021 and the three months ended June 30, 2020 was the amortization of debt issuance costs of $0.5 million and $1.9 million, respectively. For the three months ended June 30, 2021 and the three months ended June 30, 2020, we capitalized interest expense of $0.1 million and $1.9 million, respectively.

Income tax expense. We recorded $4.8 million of income tax expense for the three months ended June 30, 2021 and no income tax expense for the three months ended June 30, 2020. This resulted in an effective tax rate of approximately 16.29% and zero for the three months ended June 30, 2021 and 2020, respectively. Our effective tax rates differ from the U.S. statutory income tax rate of 21.0% primarily due to the effects of state income taxes, estimated taxable permanent differences, and valuation allowance.

Gathering and facilities segment. Prior to March 31, 2020, we had two operating segments, (i) the exploration and production segment, and (ii) the gathering and facilities segment. Please see *Note 1—Business and Organization—Deconsolidation of Elevation Midstream, LLC* to the Company's consolidated financial statements in its Annual Report for further information. After March 31, 2020, Extraction began reporting as a single reportable segment.

Combined Six Months Ended June 30, 2021 Compared to Six Months Ended June 30, 2020

Oil sales revenues. Crude oil sales revenues increased by $106.3 million to $266.8 million for the combined six months ended June 30, 2021 as compared to crude oil sales of $160.5 million for the six months ended June 30, 2020. An increase in crude oil prices contributed a $158.1 million positive impact, and a decrease in sales volumes between these periods contributed a $51.8 million negative impact. For the six months ended June 30, 2020, crude oil revenue decreased by approximately $12.3 million due to the contract term impacting the amount of consideration that could be included in the transaction price, which reduced oil sales revenue pursuant to ASC 606.

For the combined six months ended June 30, 2021, our crude oil sales averaged 25.9 MBbl/d. Our crude oil sales volume decreased by 2,236 to 4,687 MBbl for the combined six months ended June 30, 2021 compared to 6,923 MBbl for the six months ended June 30, 2020. The volume decrease is primarily due to the natural decline of our existing properties, partially offset by an increase in production from the completion of 40 gross wells from July 1, 2020 to June 30, 2021, since during the second half of 2020 and in early 2021 prior to emergence from bankruptcy, our drilling program had been suspended.

The average price we realized on the sale of crude oil was $56.92 per Bbl for the combined six months ended June 30, 2021 compared to $23.18 per Bbl for the six months ended June 30, 2020, primarily due to changes in market prices for crude oil and the $12.3 million decrease of crude oil revenue explained above.

Natural gas sales revenues. Natural gas sales revenues increased by $126.3 million to $164.6 million for the combined six months ended June 30, 2021 as compared to natural gas sales revenues of $38.3 million for the six months ended June 30, 2020. An increase in natural gas prices contributed a $132.5 million positive impact, while a decrease in sales volumes between these periods contributed a $6.2 million negative impact.

For the combined six months ended June 30, 2021, our natural gas sales averaged 169.1 MMcf/d. Natural gas sales volumes decreased by 5,936 to 30,610 MMcf for the combined six months ended June 30, 2021 as compared to 36,546 MMcf for the six months ended June 30, 2020. The volume decrease is primarily due to the the natural decline on existing producing properties, partially offset by the completion of 40 gross wells from July 1, 2020 to June 30, 2021, since during the second half of 2020 and in early 2021 prior to emergence from bankruptcy, our drilling program had been suspended.

The average price we realized on the sale of our natural gas was $5.38 per Mcf for the combined six months ended June 30, 2021 compared to $1.05 per Mcf for the six months ended June 30, 2020, primarily due to an increase in demand in February 2021 due to multiple days of severe cold as compared to the six months ended June 30, 2020.

NGL sales revenues. NGL sales revenues increased by $56.7 million to $84.7 million for the combined six months ended June 30, 2021 as compared to NGL sales revenues of $28.0 million for the six months ended June 30, 2020. An increase in price contributed a $58.6 million positive impact, while a decrease in sales volumes between these periods contributed a $1.9 million negative impact.

For the combined six months ended June 30, 2021, our NGL sales averaged 20.0 MBbl/d. NGL sales volumes decreased by 255 to 3,630 MBbl for the combined six months ended June 30, 2021 as compared to 3,885 MBbl for the six months ended June 30, 2020. The volume decrease is primarily due to the natural decline on existing producing properties, partially offset by the completion of 40 gross wells from July 1, 2020 to June 30, 2021. Our NGL sales are directly associated with our natural gas sales because our natural gas volumes are processed by third parties for both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $23.33 per Bbl for the combined six months ended June 30, 2021 compared to $7.21 per Bbl for the six months ended June 30, 2020, primarily due to an increase in demand in February 2021 due to multiple days of severe cold as compared to the combined six months ended June 30, 2020.

Lease operating expenses. Our LOE decreased by $26.5 million to $26.9 million for the combined six months ended June 30, 2021, from $53.4 million for the six months ended June 30, 2020. While oil revenue increased for the six months ended June 30, 2021, oil volumes were down for the reasons mentioned above. This allowed the company to optimize our field cost structure during the combined six months ended June 30, 2021. On a per unit basis, LOE decreased to $2.01 per BOE sold for the combined six months ended June 30, 2021 from $3.16 per BOE for the six months ended June 30, 2020.

Transportation and gathering ("T&G"). Our T&G expense increased by $1.9 million to $51.0 million for the combined six months ended June 30, 2021, from $49.1 million for the six months ended June 30, 2020. The increase in T&G was primarily due to revenue contract changes and a decrease in production during the combined six months ended June 30, 2021 compared to the six months ended June 30, 2020. On a per unit basis, T&G increased to $3.80 per BOE sold for the combined six months ended June 30, 2021 compared to $2.91 per BOE sold for the six months ended June 30, 2020.

Production taxes. Our production taxes increased by $17.5 million to $35.6 million for the combined six months ended June 30, 2021 as compared to $18.1 million for the six months ended June 30, 2020. The increase is primarily attributable to increased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 6.9% for the combined six months ended June 30, 2021 as compared to 7.9% for the six months ended June 30, 2020.

Exploration and abandonment expenses. Our exploration and abandonment expenses were $4.7 million for the combined six months ended June 30, 2021. Due to the decrease in pricing, all of the unproved property in our northern field was abandoned and impaired in the first quarter of 2020. For the six months ended June 30, 2020, we recognized $175.1 million in exploration and abandonment expenses.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense decreased $53.9 million to $104.8 million for the combined six months ended June 30, 2021 as compared to $158.7 million for the six months ended June 30, 2020. On a per unit basis, DD&A expense decreased to $7.81 per BOE for the combined six months ended June 30, 2021 from $9.39 per BOE for the six months ended June 30, 2020. These decreases are due to the $326.0

million downward fair value adjustment to the depletable asset base upon adoption of fresh start reporting, as well as an impairment of $208.5 million of proved oil and gas properties that occurred during 2020.

Impairment of long lived assets. For the combined six months ended June 30, 2021 and for the six months ended June 30, 2020, impairment expense was $0.2 million and $1.7 million, respectively. The impairment expense recorded for the six months ended June 30, 2020 related to the proved oil and gas properties in our northern field as the fair value did not exceed the carrying amount associated with the properties.

General and administrative expenses ("G&A"). General and administrative expenses decreased by $15.0 million to $20.7 million for the combined six months ended June 30, 2021 as compared to $35.7 million for the six months ended June 30, 2020. This decrease is primarily due to reductions of workforce during the first and second quarters of 2020, and a decrease in stock-based compensation expense recognized for the six months ended June 30, 2020 compared to the combined six months ended June 30, 2021. On a per unit basis, G&A expense decreased to $1.54 per BOE sold for the combined six months ended June 30, 2021 from $2.12 per BOE sold for the six months ended June 30, 2020.

Our G&A expenses for the six months ended June 30, 2020 includes $2.5 million related to the terms of separation agreements with two former executive officers. No expenses of this nature were incurred during the combined six months ended June 30, 2021.

Our G&A expenses include the non-cash expense for stock-based compensation for equity awards granted to our employees and directors. For the combined six months ended June 30, 2021, there was $5.2 million of stock-based compensation expense. For the six months ended June 30, 2020, there was $2.6 million of stock-based compensation expense.

Other operating expenses. Other operating expenses decreased by $59.3 million to $10.4 million for the combined six months ended June 30, 2021 as compared to $69.7 million for the six months ended June 30, 2020. This $59.3 million decrease is primarily due to year-over-year decreases in litigation expense of $47.2 million and early termination penalties of $9.1 million.

Commodity derivative gain (loss). Primarily due to the increase in NYMEX crude oil futures prices at June 30, 2021 as compared to December 31, 2020 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $116.9 million for the combined six months ended June 30, 2021. Primarily due to the decrease in NYMEX crude oil futures prices at June 30, 2020 as compared to December 31, 2019 and change in fair value from the execution of new positions and unwinds of existing positions, we incurred a net gain on our commodity derivatives of $193.7 million for the six months ended June 30, 2020. These gains and losses are a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program in the future. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the combined six months ended June 30, 2021, we paid commodity derivatives totaling $29.9 million. During the six months ended June 30, 2020, we received settlements of commodity derivatives totaling $166.7 million.

Loss on deconsolidation of Elevation Midstream, LLC. On March 16, 2020, we deconsolidated Elevation Midstream, LLC. Upon deconsolidation, we elected the fair value option to remeasure the Elevation equity method investment and determined it had no fair value. The Company recorded a $73.1 million loss on deconsolidation of Elevation Midstream, LLC in the condensed consolidated statements of operations for the six months ended June 30, 2020.

Reorganization items, net. Due to the commencement of the Chapter 11 Cases during the second quarter of 2020, we have incurred significant costs associated with our reorganization, primarily from damages for rejected or settled contracts and legal and professional fees. For the combined six months ended June 30, 2021, we recognized a $873.9 million gain in reorganization items, net due to emergence from bankruptcy and a gain on settlement of liabilities subject to compromise. A loss from reorganization items of $26.9 million was recognized during the six months ended June 30, 2020.

Interest expense. Interest expense consists of interest expense on our long-term debt and amortization of debt issuance costs, net of capitalized interest. For the combined six months ended June 30, 2021, we recognized interest expense of $6.7 million as compared to $41.7 million for the six months ended June 30, 2020, as a result of borrowings under our RBL Credit Facility, DIP Credit Facility, Prior Credit Facility, 2024 Senior Notes, 2026 Senior Notes and the amortization of debt issuance costs.

We incurred interest expense for the combined six months ended June 30, 2021 of $5.9 million related to our RBL Credit Facility, Prior Credit Facility and DIP Credit Facility. We incurred interest expense for the six months ended June 30, 2020 of approximately $42.5 million related to our Prior Credit Facility and DIP Credit Facility, our 2024 Senior Notes, and our 2026 Senior Notes. Also included in interest expense for the combined six months ended June 30, 2021 and for the six months ended June 30, 2020 was the amortization of debt issuance costs of $1.0 million and $3.2 million, respectively. For the combined six months ended June 30, 2021 and for the six months ended June 30, 2020, we capitalized interest expense of $0.2 million and $4.0 million, respectively.

Income tax expense. We recorded income tax expense of $28.1 million for the combined six months ended June 30, 2021 and $2.2 million for the six months ended June 30, 2020. This resulted in an effective tax rate of approximately 19.9% and (0.8)% for the combined six months ended June 30, 2021 and for the six months ended June 30, 2020, respectively. Our effective tax rates differ from the U.S. statutory income tax rate of 21.0% primarily due to the effects of state income taxes, estimated taxable permanent differences, and valuation allowance.

Liquidity and Capital Resources

Sources of Liquidity and Capital Resources

Please see *Note 1—Business and Organization—Voluntary Reorganization under Chapter 11 of the Bankruptcy Cod*e in Item 1 of the Company's filed Form 10-Q from the first quarter of 2021 for information regarding our capital structure following emergence from bankruptcy on January 20, 2021.

Historically, our primary sources of liquidity have been borrowings under our credit facilities, proceeds from securities offerings and cash proceeds from divestitures of our oil and gas properties and from the sale of oil, gas and NGL production. During the combined six months ended June 30, 2021, our primary sources of liquidity came from issuing New Common Stock, borrowings on our new RBL Credit Facility and cash from operations. Our primary uses of capital have been for the repayment of borrowings on the RBL Credit Facility and development of our oil and gas properties.

As of June 30, 2021, our outstanding RBL Credit Facility borrowings were $90.0 million. Our total available liquidity as of June 30, 2021 consisted of cash and cash equivalents of $34.4 million and $409.5 million of availability on the RBL Credit Facility. As of the date of this filing, we had drawn $70.0 million on the RBL Credit Facility and total funds available for borrowing under our RBL Credit Facility, after giving effect to an aggregate of $0.5 million of undrawn letters of credit, were $429.5 million. With available borrowings under our RBL Credit Facility and cash flow from operations, we believe we have sufficient sources of cash to meet our obligations for the next twelve months.

We enter into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations, or alternatively, we may decide to unwind or restructure the hedging arrangements into which we previously entered. The RBL Credit Agreement requires us to maintain commodity hedges covering a minimum of 65% of our anticipated oil and gas production from PDP reserves for the succeeding twelve months and 50% of our anticipated oil and gas production from PDP reserves for the next succeeding twelve months.

Material Cash Requirements

Our material short-term cash requirements include payments under our short-term lease agreements, recurring payroll and benefits obligations for our employees, capital and operating expenditures and other working capital needs. Working capital, defined as total current assets less total current liabilities, fluctuates depending on commodity pricing and effective management of receivables from our purchasers and working interest partners and payables to our vendors.

As commodity prices improve, our working capital requirements may increase as we spend additional capital, increase production and pay larger settlements on our outstanding commodity hedge contracts.

Our long-term material cash requirements from currently known obligations include repayment of outstanding borrowings and interest payment obligations under our RBL Credit Facility, settlements on our outstanding commodity hedge contracts, future obligations to plug, abandon and remediate our oil and gas properties at the end of their productive lives, and operating lease obligations. The following table summarizes our estimated material cash requirements for known obligations as of June 30, 2021 (in thousands). This table does not include repayments of outstanding borrowings on our RBL Credit Facility, or the associated interest payments, as the timing and amount of borrowings and repayments cannot be forecasted with certainty and are based on working capital requirements, commodity prices and acquisition and divestiture activity, among other factors. This table also does not include amounts payable under obligations where we cannot forecast with certainty the amount and timing of such payments, including any amounts we may be obligated to pay under our derivative contracts, as such payments are dependent on commodity prices in effect at the time of settlement.

	Payments Due by Period				
Material Cash Requirements	**Total**	**<1 Year**	**1-3 Years**	**3-5 Years**	**>5 Years**
Asset retirement obligations[1]	$ 88,714	$ 13,976	$ 22,473	$ 28,725	$ 23,540
Operating leases[2]	8,428	4,537	3,891	—	—
Total	$ 97,142	$ 18,513	$ 26,364	$ 28,725	$ 23,540

(1) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related plants and facilities.
(2) We have operating leases for certain compressors, office facilities and equipment. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however our actual expenditures under these contracts may exceed the minimum commitments presented above. Refer to *Note 7—Leases* to the Company's consolidated financial statements in its Annual Report for more information.

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	Successor	Predecessor	
	For the Period from January 21 through June 30,	For the Period from January 1 through January 20,	For the Six Months Ended June 30,
	2021	2021	2020
Net cash provided by operating activities	$ 141,769	$ 15,346	$ 83,954
Net cash used in investing activities	(41,173)	(9,120)	(191,413)
Net cash provided by (used in) financing activities	(176,831)	(101,454)	145,358

Net cash provided by operating activities

Net cash provided by operating activities for the 2021 Successor period consisted primarily of cash receipts and disbursements attributable to our normal operating cycle. The 2021 Predecessor period also consisted primarily of cash receipts and disbursements attributable to our normal operating cycle, but also contained reorganization costs related to the Company's bankruptcy and subsequent emergence. Net cash provided by operating activities for the 2020 Predecessor period was primarily comprised of settlements on commodity derivatives of $65.4 million and collections on accounts receivable related to oil, natural gas and NGLs of $56.8 million.

Net cash used in investing activities

For the combined six months ended June 30, 2021, net cash used in investing activities decreased by $141.1 million compared to the six months ended June 30, 2020 primarily as a result of $129.1 million less spent on oil and gas property additions, $10.0 million less spent on our investment in unconsolidated subsidiaries, $2.5 million less spent on other property and equipment and an increase in proceeds from the sale of assets of $9.1 million, partially offset by an increase of $5.5 million spent on the acquisition of properties in the current period and a decrease of $4.2 million from the prior period to the current period in the return of capital from gathering systems.

Net cash provided by (used in) financing activities

Net cash used in financing activities for the 2021 Successor period consisted primarily of net repayments under our RBL Credit Facility in the amount of $183.7 million partially offset by $7.0 million of proceeds from the issuance of common stock. We drew $145.5 million, net on our Prior Credit Facility and DIP Credit Facility during the six months ended June 30, 2020.

During the Predecessor period from January 1, 2021 to January 20, 2021, we extinguished both our Prior Credit Facility in the amount of $453.9 million and DIP Credit Facility in the amount of $106.7 million. Prior to and upon emergence, we drew $265.0 million on our newly established RBL Credit Facility and issued New Common Stock in the amount $200.5 million. We also incurred $6.3 million of debt issuance costs and other financing fees.

Working Capital

Working capital is defined as total current assets less total current liabilities. Our working capital deficit was $232.5 million and $369.4 million at June 30, 2021 and December 31, 2020, respectively. However, as of December 31, 2020, our current liabilities in the amount of $279.6 million were classified as "Liabilities Subject to Compromise" (excluding approximately $1.8 billion of debt, accrued interest, damages for rejected and settled contracts and other). Our cash and cash equivalents totaled $34.4 million and $205.9 million at June 30, 2021 and December 31, 2020, respectively.

Due to amounts that we incur related to our drilling and completion program and the timing of such expenditures, we may incur working capital deficits in the future. We expect that our cash flows from operating activities and availability under our RBL Credit Facility will be sufficient to fund our working capital needs. We expect that our pace of development, production volumes, realized prices for our oil, natural gas and NGL production will be the largest variables affecting our working capital.

Debt Arrangements

For details of our RBL Credit Facility, please see *Note 4—Long-Term Debt* in Item 1 of this Quarterly Report.

Equity Arrangements

For details of our equity arrangements, please see *Note 10—Equity* in Item 1 of this Quarterly Report.

Critical Accounting Policies and Estimates

Effective June 14, 2020 for the Predecessor Company, as a result of the filing of the Chapter 11 Cases, we began accounting and reporting according to ASC 852, which specifies the accounting and financial reporting requirements for entities reorganizing through chapter 11 bankruptcy proceedings. These requirements include distinguishing transactions associated with the reorganization separate from activities related to ongoing operations of the business. ASC 852 did not apply to the Successor Company.

There were no other material changes to the Company's critical accounting policies and estimates from those disclosed in its Annual Report.

Recent Accounting Pronouncements

Please see *Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements* in Item 1 of this Quarterly Report for a detailed list of recent accounting pronouncements.

Impact of Inflation/Deflation and Pricing

All of our transactions are denominated in U.S. dollars. Typically, as prices for oil and natural gas increase, associated costs rise. Conversely, as prices for oil and natural gas decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to declining commodity prices. Historically, field-level prices received for our oil and natural gas production have been volatile. During the six months ended June 30, 2020, commodity prices decreased. During the combined six months ended June 30, 2021, commodity prices increased compared to the same period in 2020. Changes in commodity prices impact our revenues, estimates of reserves, assessments of any impairment of oil and natural gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect our ability to raise capital, borrow money, and retain personnel.

Off-Balance Sheet Arrangements

As of June 30, 2021, we did not have material off-balance sheet arrangements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information required under this item.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures to ensure that the information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and to ensure that such information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Based upon that evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of June 30, 2021.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended June 30, 2021 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information regarding our legal proceedings can found in *Note 12—Commitments and Contingencies—Litigation and Legal Items* in Item 1 of this Quarterly Report.

ITEM 1A. RISK FACTORS

Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described in Item 1A of the Company's Annual Report. The risks described in our annual and quarterly reports are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results. This information should be considered carefully, together with other information in this Quarterly Report and other reports and materials we file with the SEC.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Information regarding our unregistered sales of equity securities can found in *Note 1—Business and Organization—Voluntary Reorganization under Chapter 11 of the Bankruptcy Code* in Item 1 of the Company's filed Form 10-Q from the first quarter of 2021.

The 974,056 shares of New Common Stock issued on February 4, 2021 were issued pursuant to the exemption from the registration requirements of the Securities Act, under Section 1145 of the Bankruptcy Code.

The 133,705 shares of New Common Stock issued during the second quarter of 2021 were issued pursuant to the exemption from the registration requirements of the Securities Act, under Section 1145 of the Bankruptcy Code.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

(a) Exhibits:

The exhibits listed on the accompanying Exhibit Index are filed, furnished or incorporated by reference as part of this Quarterly Report, and such Exhibit Index is incorporated herein by reference.

INDEX TO EXHIBITS

Exhibit #	Description
2.1	Agreement and Plan of Merger, dated October 17, 2016, by and between Extraction Oil & Gas, Inc. and Extraction Oil & Gas Holdings, LLC. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
2.2	Sixth Amended Joint Plan of Reorganization of Extraction Oil & Gas, Inc. and its Debtor Affiliates Pursuant to Chapter 11 of the Bankruptcy Code (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed on December 30, 2020).
2.3	Agreement and Plan of Merger, dated as of May 9, 2021, by and among Bonanza Creek Energy, Inc., Raptor Eagle Merger Sub, Inc. and Extraction Oil & Gas, Inc.(incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on May 10, 2021).
2.4	Agreement and Plan of Merger, dated as of June 6, 2021, by and among Bonanza Creek Energy, Inc., Raptor Condor Merger Sub 1, Inc., Raptor Condor Merger Sub 2, LLC, Crestone Peak Resources LP, CPPIB Crestone Peak Resources America Inc., Crestone Peak Resources Management LP and Extraction Oil & Gas, Inc (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on June 8, 2021).
2.5	Amendment No. 1 to Agreement and Plan of Merger, dated as of June 6, 2021, by and among Bonanza Creek Energy, Inc., Raptor Eagle Merger Sub, Inc. and Extraction Oil & Gas, Inc (incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on June 8, 2021).
3.1	Amended and Restated Certificate of Incorporation of Extraction Oil & Gas, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on January 20, 2021).
3.2	Amended and Restated Bylaws of Extraction Oil & Gas, Inc. (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on January 20, 2021).
10.1	Amendment No. 2 to Credit Agreement, dated May 6, 2021, by and among the Company, as borrower, certain subsidiaries of the Company, as guarantors, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent for the Lenders and as issuing lender.
10.2	Voting Agreement, dated as of May 9, 2021, by and among Bonanza Creek Energy, Inc., Extraction Oil & Gas, Inc. and Kimmeridge Energy Management Company, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on May 10, 2021).
10.3	Amendment No. 3 to Credit Agreement, dated May 28, 2021, by and among the Company, as borrower, certain subsidiaries of the Company, as guarantors, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent for the Lenders and as issuing lender (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on June 1, 2021).
10.4	Amended and Restated Voting Agreement, dated as of June 6, 2021 and effective as of May 9, 2021, by and among Bonanza Creek Energy, Inc., Extraction Oil & Gas, Inc. and Kimmeridge Energy Management Company, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on June 8, 2021).
*31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
**32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	Interactive Data Files

†	Management contract or compensatory plan or agreement.
*	Filed herewith.
**	Furnished herewith.

SIGNATURES

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

Date: August 9, 2021

Extraction Oil & Gas, Inc.

By: /s/ Thomas B. Tyree Jr.
Thomas B. Tyree Jr.
Chief Executive Officer
(Principal Executive Officer)

By: /s/ Marianella Foschi
Marianella Foschi
Chief Financial Officer
(Principal Financial Officer)

By: /s/ Tom L. Brock
Tom L. Brock
Chief Accounting Officer
(Principal Accounting Officer)

Exhibit 31.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Thomas B. Tyree Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q (this “Report”) of Extraction Oil & Gas, 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 officer 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 officer 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.

Date: August 9, 2021

/s/ Thomas B. Tyree Jr.
Thomas B. Tyree Jr.
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Marianella Foschi, certify that:

1. I have reviewed this quarterly report on Form 10-Q (this "Report") of Extraction Oil & Gas, 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 officer 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 officer 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.

Date: August 9, 2021

/s/ Marianella Foschi
Marianella Foschi
Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2021 of Extraction Oil & Gas, Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Thomas B. Tyree Jr., Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my 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 the Company.

Date: August 9, 2021

/s/ Thomas B. Tyree Jr.
Thomas B. Tyree Jr.
Chief Executive Officer
(Principal Executive Officer)

Exhibit 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2021 of Extraction Oil & Gas, Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Marianella Foschi, Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my 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 the Company.

Date: August 9, 2021

/s/ Marianella Foschi
Marianella Foschi
Chief Financial Officer
(Principal Financial Officer)