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

FORM 10-K

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

For the fiscal year ended December 31, 2021
Commission File Number: 001-35467

Battalion Oil Corporation
(Exact name of registrant as specified in its charter)

Delaware	**20-0700684**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

3505 West Sam Houston Parkway North, Suite 300, Houston, TX 77043
(Address of principal executive offices)

(832) 538-0300
(Registrant's telephone number)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock par value $0.0001	BATL	NYSE American

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No x

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 x 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 x No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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 x	Smaller reporting company x
			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 a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

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

As of March 3, 2022, there were 16,337,030 shares outstanding of registrant's $.0001 par value common stock. Based upon the closing price for the registrant's common stock on the New York Stock Exchange as of June 30, 2021, the aggregate market value of shares of common stock held by non-affiliates of the registrant was approximately $49.9 million.

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

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13, and 14, is incorporated by reference to portions of the registrant's definitive proxy statement for its 2021 annual meeting of stockholders which will be filed no later than 120 days after December 31, 2021.

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Special note regarding forward-looking statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, are forward-looking statements and may concern, among other things, planned capital expenditures, potential increases in oil and natural gas production, potential costs to be incurred, future cash flows and borrowings, our financial position, business strategy and other plans and objectives for future operations. These forward-looking statements may be identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "objective," "believe," "predict," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. Readers should consider carefully the risks described under the "Risk Factors" section of this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in forward-looking statements, which include, but are not limited to, the following factors:

- volatility in commodity prices for oil, natural gas and natural gas liquids;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and develop our undeveloped acreage positions;
- impacts and potential risks related to actual or anticipated pandemics, such as the novel coronavirus (COVID-19) pandemic, including how it has and may continue to impact our operations, financial results, liquidity, contractors, customers, employees and vendors;
- our indebtedness, which may increase in the future, and higher levels of indebtedness can make us more vulnerable to economic downturns and adverse developments in our business;
- our ability to replace our oil and natural gas reserves and production;
- the presence or recoverability of estimated oil and natural gas reserves attributable to our properties and the actual future production rates and associated costs of producing those oil and natural gas reserves;
- our ability to successfully develop our large inventory of undeveloped acreage;
- our ability to secure adequate sour gas treating and/or sour gas take-away capacity in our Monument Draw area sufficient to handle production volumes;
- drilling and operating risks, including accidents, equipment failures, fires, and leaks of toxic or hazardous materials, such as H2S, which can result in injury, loss of life, pollution, property damage and suspension of operations;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars;
- our ability to retain key members of senior management, the board of directors and key technical employees;
- senior management's ability to execute our plans to meet our goals;
- access to and availability of water, sand and other treatment materials to carry out fracture stimulations in our completion operations;
- the possibility that our industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulations);
- access to adequate gathering systems, processing and treating facilities and transportation take-away capacity to move our production to marketing outlets to sell our production at market prices;
- contractual limitations that affect our management's discretion in managing our business, including covenants that, among other things, limit our ability to incur debt, make investments and pay cash dividends;
- the potential for production decline rates for our wells to be greater than we expect;
- competition, including competition for acreage in our resource play;
- environmental risks, such as accidental spills of toxic or hazardous materials, and the potential for environmental liabilities;
- exploration and development risks;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as the conflict between Ukraine and Russia, and acts of terrorism or sabotage;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions

in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access capital;
- other economic, competitive, governmental, regulatory, legislative, including federal and state regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or oil and natural gas prices;
- our insurance coverage may not adequately cover all losses that we may sustain; and
- title to the properties in which we have an interest may be impaired by title defects.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, 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.

Glossary of Oil and Natural Gas Terms

The definitions set forth below apply to the indicated terms as used in this report. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of one-pound of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed property. Property where wells have been drilled and production equipment has been installed.

Development well. A well drilled within the proved areas of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Extension well. A well drilled to extend the limits of a known reservoir.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Hydraulic fracturing. The injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production.

H2S. Hydrogen sulfide, a colorless, flammable and extremely hazardous naturally occurring gas that is sometimes produced from oil and natural gas wells.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million Boe.

MMBtu. One million Btu.

MMcf. One million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. Natural gas liquids, i.e. hydrocarbons removed as a liquid, such as ethane, propane and butane.

Operator. The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production.

Proved developed reserves. Proved reserves that are expected to be recovered from existing wellbores, whether or not currently producing, without drilling additional wells. Production of such reserves may require a recompletion.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has been previously completed.

Reserve-to-production ratio or Reserve life. A ratio determined by dividing estimated existing reserves determined as of the stated measurement date by production from such reserves for the prior twelve month period.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Spud. Commencement of actual drilling operations.

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

PART I

ITEM 1. BUSINESS

Overview

Unless the context otherwise requires, all references in this report to "Battalion," "our," "us," and "we" refer to Battalion Oil Corporation and its subsidiaries, as a common entity. Battalion is the successor reporting company to Halcón Resources Corporation (Halcón). On January 21, 2020, we filed a Certificate of Amendment to our Amended and Restated Certificate of Incorporation with the Delaware Secretary of State to effect a change of our corporate name from Halcón Resources Corporation to Battalion Oil Corporation.

Certain prior year financial statements are not comparable to our current year financial statements due to the adoption of fresh-start accounting upon our emergence from chapter 11 bankruptcy on October 8, 2019. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to October 1, 2019, the convenience date applied for fresh-start accounting. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company prior to, and including, October 1, 2019.

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. During 2017, we acquired certain properties in the Delaware Basin and divested our assets located in the Williston Basin in North Dakota and in the El Halcón area of East Texas. As a result, our properties and drilling activities are currently focused in the Delaware Basin, where we have an extensive drilling inventory that we believe offers attractive long-term economics.

At December 31, 2021, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell) using the Securities and Exchange Commission (SEC) prices for crude oil and natural gas, which are based on preceding 12-month first day of the month average crude oil spot prices of West Texas Intermediate (WTI) of $66.55 per Bbl and Henry Hub natural gas spot price of $3.60 per MMBtu, were approximately 95.9 MMBoe, consisting of 58.7 MMBbls of oil, 16.3 MMBbls of natural gas liquids and 125.0 Bcf of natural gas. Approximately 44% of our estimated proved reserves were classified as proved developed as of December 31, 2021. We maintain operational control of 99.9% of our estimated proved reserves.

Our total operating revenues for the year ended December 31, 2021 were approximately $285.2 million compared to total operating revenues for the year ended December 31, 2020 of approximately $148.3 million. The increase in revenues is primarily attributable to an approximate $24.14 per Boe increase in average realized prices (excluding the effects of hedging arrangements). Full year 2021 production averaged 16,241 Boe/d compared to average daily production of 16,858 Boe/d for 2020. Average daily oil and natural gas production was impacted by the temporary shut-in of production amounting to approximately 300 Boe/d and 1,300 Boe/d for the year ended December 31, 2021 and 2020, respectively. In February 2021, we temporarily shut-in production due to inclement weather. In May and June 2020, we temporarily shut-in production in response to historically low commodity prices. Current year production was also impacted by third-party processing curtailments and downtime resulting from facility upgrades and repairs. In 2021, we drilled and cased 2.0 gross (2.0 net) operated wells, completed 6.0 gross (6.0 net) operated wells, and put online 6.0 gross (6.0 net) operated wells.

Recent Developments

Risk and Uncertainties

We are continuously monitoring the current and potential impacts of the novel coronavirus (COVID-19) pandemic on our business, including how it has and may continue to impact our operations, financial results, liquidity, contractors, customers, employees and vendors, and taking appropriate actions in response, including implementing various measures to ensure the continued operation of our business in a safe and secure manner. In 2020, COVID-19 and governmental actions to contain the pandemic contributed to an economic downturn, reduced demand for oil and natural gas and, together with a price war involving the Organization of Petroleum Exporting Countries (OPEC)/Saudi Arabia and Russia, depressed oil and natural gas prices to historically low levels. Although OPEC and Russia subsequently agreed to reduce production, downward pressure on prices continued for several months, particularly given concerns over the impacts of the economic downturn on demand. As a consequence, beginning in March 2020, we realized lower revenue as a result of commodity price declines, resulting in us temporarily shutting in producing wells in May and June 2020, which further contributed to lower revenues that year. Additionally in 2020, we incurred ceiling test impairments, which were primarily driven by a decline in the average pricing required to be used in the valuation of our reserves for ceiling test purposes.

During 2021, widespread availability of COVID-19 vaccines in the United States and elsewhere combined with accommodative governmental monetary and fiscal policies and other factors, led to a rebound in demand for oil and natural gas and increases in oil and natural gas prices. Further, at present, OPEC and Russia have been coordinating production increases to maintain supply and demand balance, stabilize prices and avoid market disruptions. However, there remains the potential for such cooperation to fail and for demand for oil and natural gas to be adversely impacted by the economic effects of the ongoing COVID-19 pandemic, including as a consequence of the circulation of more infectious "variants" of the disease, vaccine hesitancy, waning vaccine effectiveness or other factors. As a consequence, we are unable to predict whether oil and natural gas prices will remain at current levels or will be adversely impacted by the same sorts of factors that negatively impacted prices during 2020. Furthermore, the health of our employees, contractors and vendors, and our ability to meet staffing needs in our operations and critical functions remain concerns and cannot be predicted, nor can the impact on our customers, vendors and contractors. Any material effect on these parties could adversely impact us. These and other factors could affect our operations, earnings and cash flows and could cause our results to not be comparable to those of the same period in previous years. The results presented in this Form 10-K are not necessarily indicative of future operating results. For further information regarding the actual and potential impacts of COVID-19 on us, see *"Risk Factors"* in Item 1A of this Annual Report on Form 10-K.

Term Loan Credit Facility

On November 24, 2021, we and our wholly owned subsidiary, Halcón Holdings, LLC (Borrower) entered into an Amended and Restated Senior Secured Credit Agreement (Term Loan Agreement) with Macquarie Bank Limited, as administrative agent, and certain other financial institutions party thereto, as lenders. The Term Loan Agreement amends and restates in its entirety our Senior Credit Agreement as discussed below. Pursuant to the Term Loan Agreement, the lenders have agreed to loan us (i) $200.0 million, which funded on November 24, 2021 and was partially used to refinance all amounts owed under the Senior Credit Agreement; (ii) up to $20.0 million, available to be drawn up to 18 months from November 24, 2021, subject to the satisfaction of certain conditions; and (iii) up to $15.0 million, which amount will be available to be drawn from the date certain wells included in the approved plan of development (APOD) are deemed producing APOD wells until up to 18 months after November 24, 2021, subject to the satisfaction of certain conditions. An additional $5.0 million is available for the issuance of letters of credit. The maturity date of the Term Loan Agreement is November 24, 2025. Until such maturity date, borrowings under the Term Loan Agreement bear interest at a rate per annum equal to LIBOR (or another applicable reference rate, as determined pursuant to the provisions of the Term Loan Agreement) plus an applicable margin of 7.00%. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 6, *"Debt"* for additional information on the Term Loan Agreement.

Senior Revolving Credit Facility

On November 24, 2021, our Senior Secured Revolving Credit Agreement (Senior Credit Agreement) was amended and restated in its entirety by the Term Loan Agreement. Borrowings outstanding under the Senior Credit Agreement were repaid with proceeds from the Term Loan Agreement resulting in a charge of $0.1 million presented in *"Gain (loss) on extinguishment of debt"* in the consolidated statements of operations for the year ended December 31, 2021.

On September 24, 2021, we entered into the Fifth Amendment to Senior Secured Revolving Credit Agreement (the Fifth Amendment) which, among other things, modified the limits on swap agreements so as not to exceed, (i) from the period of the Fifth Amendment effective date through December 31, 2021, the percentage of the reasonably anticipated hydrocarbon production from proved developed producing reserves during such period hedged pursuant to secured swap agreements in place as of the Fifth Amendment effective date; (ii) for the fiscal year ending December 31, 2022, the greater of (a) the proved developed producing reserves during such fiscal year hedged pursuant to secured swap agreements in place as of the Fifth Amendment effective date and (b) 85% of the proved developed producing reserves during such fiscal year; and (iii) for the fiscal years ending December 31, 2023, December 31, 2024 and December 31, 2025, swap agreements not to exceed 85%, 70% and 60% of the proved developed producing reserves, respectively, during each fiscal year.

On May 10, 2021, we entered into the Fourth Amendment to Senior Secured Revolving Credit Agreement (the Fourth Amendment) which reduced the borrowing base to $185.0 million effective June 1, 2021 and further reduced the borrowing base to $175.0 million effective September 1, 2021. The Fourth Amendment also, among other things, (i) increased interest margins to 2.00% to 3.00% for ABR-based loans and 3.00% to 4.00% for Eurodollar-based loans, (ii) amended the covenant relating to the minimum mortgaged total value of proved borrowing base properties to increase the value from 90% to 95%, (iii) provided for direct reductions in the borrowing base in the event of asset dispositions in excess of $1.0 million per fiscal year or swap terminations and (iv) revised certain covenants and covenant-related baskets including, but not limited to, adding covenants prohibiting the designation of unrestricted subsidiaries and requiring prior consent from the lenders regarding asset dispositions or swap terminations in excess of the greater of $7.5 million or 3.5% of the then effective borrowing base.

Paycheck Protection Program Loan

Effective August 13, 2021, the principal amount of our promissory note (the PPP Loan) under the Paycheck Protection Program of the Coronavirus Aid, Relief and Economic Security Act (the CARES Act) was reduced from $2.2 million to $0.2 million by the U.S. Small Business Administration (SBA). We applied for forgiveness of the amount due on the PPP Loan based on the use of the loan proceeds on eligible expenses in accordance with the terms of the CARES Act. We recorded a gain on the extinguishment of the forgiven portion of the PPP Loan and related accrued interest of $2.1 million. The gain is presented in *"Gain (loss) on extinguishment of debt"* in the consolidated statements of operations for the year ended December 31, 2021.

Employee Retention Credit

The CARES Act included, among other things, provisions relating to refundable payroll tax credits (the Employee Retention Credit or ERC). As provided for in the CARES Act and subsequent legislation which modified and extended the provisions included therein, the ERC allows for a refundable tax credit against certain employment taxes equal to 50% of the first $10,000 in qualified wages paid to each employee after March 12, 2020 and through December 31, 2020 and 70% of the first $10,000 in qualified wages paid to each employee, per calendar quarter, after December 31, 2020 through September 30, 2021. During the year ended December 31, 2021, we determined that the qualifications for the Employee Retention Credit were met and filed the corresponding applications for the applicable 2020 and 2021 periods. We recognized an approximate $0.7 million Employee Retention Credit during the year ended December 31, 2021, with approximately $0.5 million recorded to *"General and administrative"* and approximately $0.2 million recorded to *"Lease operating"* in the consolidated statements of operations.

2022 Capital Budget

We expect to spend approximately $130.0 million to $150.0 million on capital expenditures during 2022. Overall, we currently plan to drill 12 gross operated wells during the year, complete 9 to 13 gross operated wells, and bring 8 to 12 gross operated wells on production. Our 2022 capital budget currently contemplates running one operated rig in the Delaware Basin during the year. We continuously monitor changes in market conditions and adapt our operational plans as necessary in order to maintain financial flexibility, preserve core acreage and meet contractual obligations, and therefore our capital budget is subject to change.

We expect to fund our budgeted 2022 capital expenditures with cash and cash equivalents on hand from the funding of the Term Loan Agreement and cash flows from operations. In the event our cash flows are materially less than anticipated or our costs are materially greater than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may be required to curtail drilling, development, land acquisitions and other activities to reduce our capital spending.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominately upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, transportation take-away capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

Business Strategy

Our primary long-term objective is to increase stockholder value by safely and cost-effectively increasing our production of oil, natural gas and natural gas liquids, adding to our proved reserves and growing our inventory of economic drilling locations, while acting as a responsible corporate citizen in the communities in which we operate. To accomplish this objective, we intend to execute the following business strategies:

- ***Develop our Liquids-Rich Acreage Positions to Grow Production and Reserves Efficiently.*** We intend to drill and develop our multi-zone resource play to maximize value and resource potential. Our near-term development plans are focused on production growth and acreage preservation in our liquids-rich Monument Draw area.
- ***Enhance Returns Through Continued Improvements in Operational and Cost Efficiencies.*** We are the operator for the majority of our acreage, which gives us control over the timing of capital expenditures, execution and costs. It also allows us to adjust our capital spending based on drilling results and the economic environment. As operator, we are able to evaluate industry drilling results and implement improved operating practices that may enhance our initial production rates, ultimate recovery factors and rate of return on invested capital. In addition to operational efficiencies, we continue to focus on cost-saving measures to reduce corporate administrative expenses.
- ***Maintain Financial Flexibility.*** Our management team is focused on maintaining adequate liquidity while pursuing our near-term development plans. We believe our internally-generated cash flows and the funding from our Term Loan Agreement will provide us with sufficient liquidity to execute our current capital program and strategy. We have no material near-term debt maturities. We also employ a hedging program to reduce the variability of our cash flows used to support our capital spending.
- ***Attain Growth Through Strategic Business Combinations.*** We intend to pursue merger and acquisition opportunities to meet our strategic and financial targets, including the maintenance of a conservative leverage position. Selective business combinations provide opportunities to acquire high quality assets complementary to our core acreage, expand our drilling inventory and gain operational scale. We believe our management team's geologic and engineering expertise, particularly in the Permian Basin, provides a competitive advantage in the identification of acquisition targets and evaluation of resource potential.

Oil and Natural Gas Reserves

The proved reserves estimates reported herein for the years ended December 31, 2021, 2020 and 2019, have been independently evaluated by Netherland, Sewell, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland, Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland, Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland, Sewell reserves reports incorporated herein are Mr. Neil H. Little and Mr. Edward C. Roy III. Mr. Little, a Licensed Professional Engineer in the State of Texas (No. 117966), has been practicing consulting petroleum engineering at Netherland, Sewell since 2011 and has over nine years of prior industry experience. He graduated from Rice University in 2002 with a Bachelor of Science Degree in Chemical Engineering and from University of Houston in 2007 with a Master of Business Administration Degree. Mr. Roy, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 2364), has been practicing consulting petroleum geoscience at Netherland, Sewell since 2008 and has over 11 years of prior industry experience. He graduated from Texas Christian University in 1992 with a Bachelor of Science Degree in Geology and from Texas A&M University in 1998 with a Master of Science Degree in Geology. Netherland, Sewell has reported to us that both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; they are both proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our board of directors has established a reserves committee composed of independent directors with experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Executive Vice President and Chief Operating Officer. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to our board of directors as to whether to approve the report prepared by our independent engineering firm. Mr. Daniel P. Rohling, our Executive Vice President and Chief Operating Officer, is primarily responsible for overseeing the preparation of the annual reserve report by Netherland, Sewell. He has approximately 15 years of oil and gas operations experience and earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University and is an active member of the Society of Petroleum Engineers.

The reserves information in this Annual Report on Form 10-K represents only estimates. Reserve evaluation is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary significantly. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by Netherland, Sewell and other information about our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data*—"*Supplemental Oil and Gas Information (Unaudited)*."

Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month for the 12-month period ended December 31, 2021. Average prices for the 12-month period were as follows: WTI crude oil spot price of $66.55 per Bbl, adjusted by lease or field for quality, transportation fees, and market differentials and a Henry Hub natural gas spot price of $3.60 per MMBtu, as adjusted by lease or field for energy content, transportation fees, and market differentials. All prices and costs associated with operating wells were held constant in accordance with SEC guidelines.

The following table presents certain proved reserve information as of December 31, 2021:

Proved Reserves (MBoe)[(1)]	
Developed	42,410
Undeveloped	53,470
Total	95,880

(1) *Determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on approximate energy equivalency. This is an energy content correlation and does not reflect the value or price relationship between the commodities.*

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2021 and 2020. Shut-in wells currently not capable of production are excluded from the well information below.

	Years Ended December 31,			
	2021		2020	
	Gross	Net	Gross	Net
Oil	107	84.4	103	82.5
Natural Gas	8	6.4	10	7.2
Total	115	90.8	113	89.7

Oil and Natural Gas Production

Core Resource Play—Delaware Basin

We have working interests in 40,372 net acres in the Delaware Basin as of December 31, 2021 in Pecos, Reeves, Ward and Winkler Counties, Texas. This core resource play is characterized by high oil and liquids-rich natural gas content in thick, continuous sections of source rock that can provide repeatable drilling opportunities and significant initial production rates. Our primary targets in this area are the Wolfcamp and Bone Spring formations. As of December 31, 2021, we had 95 operated wells producing in this area in addition to minor working interests in 13 non-operated wells. Our average daily net production from this area for the year ended December 31, 2021 was 16,219 Boe/d. As of December 31, 2021, estimated proved reserves for the Delaware Basin were approximately 95.8 MMBoe, of which approximately 44% were classified as proved developed and approximately 56% as proved undeveloped.

Risk Management

We have designed a risk management policy for the use of derivative instruments to provide initial protection against certain risks relating to our ongoing business operations, such as commodity price declines and price differentials between the NYMEX commodity price and the index price at the location where our production is sold. Derivative contracts are utilized to hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales of future oil and natural gas production. Our requirement, under our Term Loan Agreement, is to hedge approximately 50% to 85% of our anticipated oil and natural gas production, in varying percentages by year, and on a rolling basis for the next four years. However, our decision on the price at which we choose to hedge our production is based in part on our view of current and future market conditions. Our hedge policies and objectives change as our operational profile changes but remain consistent with the requirements in effect under our Term Loan Agreement. Our future performance is subject to commodity price risks and our future cash flows from operations may be volatile. We do not enter into derivative contracts for speculative trading purposes.

While there are many different types of derivatives available, we typically use fixed-price swap, costless collar, basis swap, and WTI NYMEX roll agreements to attempt to manage price risk. The fixed-price swap agreements call for payments to, or receipts from, counterparties depending on whether the index price of oil or natural gas for the period is greater or less than the fixed price established for the period contracted under the fixed-price swap agreement. Costless collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All costless collar agreements provide for payments to counterparties if the settlement price under the agreement exceeds the ceiling and payments from the counterparties if the settlement price under the agreement is below the floor. Basis swaps effectively lock in a price differential between regional prices (i.e. Midland) where the product is sold and the relevant pricing index under which the oil production is hedged (i.e. Cushing). WTI NYMEX roll agreements account for pricing adjustments to the trade month versus the delivery month for contract pricing.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. As of December 31, 2021, we did not post collateral under any of our derivative contracts as they are secured under our Term Loan Agreement. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about*

Market Risk and Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 8, *"Derivative and Hedging Activities,"* for additional information.

Oil and Natural Gas Operations

Our principal properties consist of leasehold interests in developed and undeveloped oil and natural gas properties and the reserves associated with these properties. Generally, our oil and natural gas leases remain in force as long as production in paying quantities is maintained. Leases on undeveloped oil and natural gas properties are typically for a primary term of three to five years within which we are generally required to develop the property or the lease will expire. In some cases, the primary term of leases on our undeveloped properties can be extended by option payments; the amount of any payments and time extended vary by lease. The table below sets forth the results of our drilling activities for the periods indicated:

	Years Ended December 31,					
	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (1)	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total Exploratory	—	—	—	—	—	—
Extension Wells:						
Productive (1)	—	—	—	—	11	9.9
Dry	—	—	—	—	—	—
Total Extension	—	—	—	—	11	9.9
Development Wells:						
Productive (1)	6	6.0	7	6.3	7	6.1
Dry	—	—	—	—	—	—
Total Development	6	6.0	7	6.3	7	6.1
Total Wells:						
Productive (1)	6	6.0	7	6.3	18	16.0
Dry	—	—	—	—	—	—
Total	6	6.0	7	6.3	18	16.0

(1) *Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly extension or exploratory wells where there is no production history.*

We own interests in developed and undeveloped oil and natural gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying provisions. The following table presents a summary of our acreage interests as of December 31, 2021:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
State	Gross	Net	Gross	Net	Gross	Net
North Dakota	3,600	694	33,885	13,894	37,485	14,588
Texas	31,074	29,288	12,338	11,084	43,412	40,372
Total Acreage	34,674	29,982	46,223	24,978	80,897	54,960

The table below reflects the percentage of our total net undeveloped acreage as of December 31, 2021 that will expire each year if we do not establish production in paying quantities on the units in which such acreage is included or do not pay (to the extent we have the contractual right to pay) delay rentals or obtain other extensions to maintain the lease.

Year	Percentage Expiration
2022	52 %
2023	— %
2024	— %
2025 & beyond	48 %
	100 %

Of the acreage with 2022 expiration dates, approximately one net acre relates to our core area of operations. We continually review our near-term lease expirations to preserve acreage in our core area of operations, either through our drilling program or through lease extensions or renewals, if necessary. We have no current plans to drill on acreage in areas outside of our core area of operations.

At December 31, 2021, we had estimated proved reserves of approximately 95.9 MMBoe comprised of 58.7 MMBbls of crude oil, 16.3 MMBbls of natural gas liquids, and 125.0 Bcf of natural gas. The following table sets forth these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Oil (MBbls)	21,694	37,038	58,732
Natural Gas Liquids (MBbls)	8,881	7,439	16,320
Natural Gas (MMcf)	71,009	53,956	124,965
Equivalent (MBoe)(1)	42,410	53,470	95,880

(1) *Determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on approximate energy equivalency. This is an energy content correlation and does not reflect the value or price relationship between the commodities.*

At December 31, 2021, total estimated proved reserves were approximately 95.9 MMBoe, a 32.5 MMBoe net increase from the previous year's estimate of 63.4 MMBoe. The net increase in total proved reserves was the result of additions and extensions of 26.5 MMBoe and positive revisions of 11.9 MMBoe due primarily to increases in SEC pricing, partially offset by production of 5.9 MMBoe.

At December 31, 2021, our estimated proved undeveloped (PUD) reserves were approximately 53.5 MMBoe, a 26.4 MMBoe net increase from the previous year's estimate of 27.1 MMBoe. The net increase in total PUD reserves was the result of additions and extensions of 26.5 MMBoe and positive revisions of 1.9 MMBoe due primarily to increases in SEC pricing, partially offset by development of 2.1 MMBoe.

As of December 31, 2021, all of our PUD reserves are planned to be developed within five years from the date they were initially recorded. During 2021, approximately $37.6 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

Reliable technologies were used to determine areas where PUD locations are more than one offset location away from a producing well. These technologies include seismic data, wire line openhole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic estimated ultimate recoveries from individual producing wells. We relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves. Out of total PUD reserves of 53.5 MMBoe at December 31, 2021, 37.7 MMBoe were associated with 39 gross PUD locations that were more than one offset location from a producing well.

The estimates of quantities of proved reserves contained in this report were made in accordance with the definitions contained in SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*. For additional information on our oil and natural gas reserves, including a table detailing the changes by year of our proved reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data —"Supplemental Oil and Gas Information (Unaudited)."* We account for our oil and natural gas producing activities using the full cost method of accounting in accordance with SEC regulations. Accordingly, all costs incurred in the acquisition, exploration, and development of proved and unproved oil and natural gas properties, including the costs of abandoned properties, treating equipment and gathering support facilities, dry holes, geophysical costs, direct internal costs and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a quarterly full cost ceiling test. See further discussion in Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 5, *"Oil and Natural Gas Properties."*

Capitalized costs of our evaluated and unevaluated properties at December 31, 2021, 2020 and 2019 are summarized as follows (in thousands):

	December 31, 2021	December 31, 2020	December 31, 2019
Oil and natural gas properties (full cost method):			
Evaluated	$ 569,886	$ 509,274	$ 420,609
Unevaluated	64,305	75,494	105,009
Gross oil and natural gas properties	634,191	584,768	525,618
Less - accumulated depletion	(339,776)	(295,163)	(19,474)
Net oil and natural gas properties	$ 294,415	$ 289,605	$ 506,144

The following table summarizes our oil, natural gas and natural gas liquids production volumes, average sales price per unit and average costs per unit:

	Successor			Predecessor
	Years Ended December 31,		Period from October 2, 2019 through December 31, 2019	Period from January 1, 2019 through October 1, 2019
	2021	2020		
Production:				
Crude oil - MBbl				
Delaware Basin	3,191	3,430	1,050	2,718
Other	5	16	7	5
Total	3,196	3,446	1,057	2,723
Natural gas - MMcf				
Delaware Basin	9,444	8,744	2,754	6,378
Other	3	25	1	3
Total	9,447	8,769	2,755	6,381
Natural gas liquids - MBbl				
Delaware Basin	1,155	1,258	351	911
Other	2	4	—	—
Total	1,157	1,262	351	911
Production:				
Total MBoe [(1)]	5,928	6,170	1,867	4,698
Average daily production - Boe [(1)]	16,241	16,858	20,293	17,209
Average price per unit (excluding impact of settled derivatives)**:**				
Crude oil price - Bbl	$ 66.81	$ 36.56	$ 55.18	$ 53.26
Natural gas price - Mcf	3.73	0.66	0.62	0.02
Natural gas liquids price - Bbl	30.59	11.86	14.45	14.52
Barrel of oil equivalent price - Boe [(1)]	47.93	23.79	34.88	33.71
Average price per unit (including impact of settled derivatives)[(2)]**:**				
Crude oil price - Bbl	$ 43.79	$ 48.87	$ 54.15	$ 52.33
Natural gas price - Mcf	3.27	0.94	0.81	0.96
Natural gas liquids price - Bbl	30.59	11.86	21.76	23.90
Barrel of oil equivalent price - Boe [(1)]	34.79	31.07	35.94	36.26
Average cost per Boe:				
Production:				
Lease operating	$ 7.42	$ 6.82	$ 6.86	$ 8.43
Workover and other	0.54	0.60	0.89	1.19
Taxes other than income	2.08	1.63	2.00	1.96
Gathering and other	10.19	9.08	5.79	7.67
Total average cost	20.23	18.13	15.54	19.25

(1) *Determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on approximate energy equivalency. This is an energy content correlation and does not reflect the value or price relationship between the commodities.*

(2) *Cash paid on, or cash received from, settled derivative contracts are reflected as "Net gain (loss) on derivative contracts" in the consolidated statements of operations, consistent with our decision not to elect hedge accounting.*

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers, transporters and take-away capacity for the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Markets and Major Customers

The purchasers of our oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, we have not experienced any significant losses from uncollectible accounts. In 2021, three individual purchasers of our production, Western Refining Inc., Sunoco Inc. and Salt Creek Midstream, LLC, each accounted for more than 10% of total sales, collectively representing 73% of our total sales for the year. In 2020, two individual purchasers of our production, Western Refining Inc. and Sunoco Inc., each accounted for more than 10% of total sales, collectively representing 57% of our total sales for the year. For the combined periods of October 2, 2019 through December 31, 2019, and January 1, 2019 through October 1, 2019, two individual purchasers of our production, Western Refining Inc. and Sunoco Inc., each accounted for more than 10% of total sales, collectively representing 80% of our total sales for the period.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for crude oil can often be higher in the summer months during the peak travel season. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to be overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other events may cause accidental releases of toxic or hazardous materials, such as hydrogen sulfide, petroleum liquids, or drilling fluids into the environment, or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our operating results, financial position or cash flows. For further discussion on risks see Item 1A. *Risk Factors.*

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form spacing units and therefore difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose requirements regarding the ratability of production. On some occasions, local authorities have imposed moratoria or other restrictions on exploration and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration and production to proceed.

The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically govern the permitting, construction and operation of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Failure to comply with environmental laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

Beyond existing requirements, new programs and changes in existing programs may address various aspects of our business, including naturally occurring radioactive materials, oil and natural gas exploration and production, air emissions, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons may include the current or former owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances released into the environment, for damages to natural resources and for the costs of some health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

Under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, most wastes generated by the exploration and production of oil and natural gas are not regulated as hazardous waste. Periodically, however, there are proposals to reclassify oil and gas wastes as hazardous wastes or to subject them to enhanced solid waste regulation. If such proposals were to be enacted, they could have a significant impact on our operating costs and on those of all the industry in general.

In the ordinary course of our operations, moreover, we do handle materials that may be subject to extensive existing RCRA regulations or that may be classified as hazardous substances under CERCLA. From time to time, releases of those materials have occurred at locations we own or at which we have operations. Under CERCLA, RCRA and analogous state laws, we have been and may be required to remove or remediate such materials.

Water Discharges

Our operations also may be subject to the federal Clean Water Act and analogous state statutes. Those laws regulate discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of spill prevention, control, and countermeasure plans in connection with on-site storage of significant quantities of oil. In the event of a discharge of oil into U.S. waters, we could be liable under the Oil Pollution Act for cleanup costs, damages and economic losses.

Our oil and natural gas production also generates salt water, which we dispose of by underground injection. The federal Safe Drinking Water Act (SDWA), the Underground Injection Control (UIC) regulations promulgated under the SDWA, and related state programs regulate the drilling and operation of salt water disposal wells. The EPA directly administers the UIC program in some states, and in others it is delegated to the state. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing

Our completion operations are subject to regulations that may become more stringent in either the short- or long-term. In particular, the well completion technique known as hydraulic fracturing, which is used to stimulate production of oil and natural gas, has come under increased scrutiny by the environmental community, and many local, state and federal regulators. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depths to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with substantially all of the wells for which we are the operator.

Working at the direction of Congress, the EPA issued a study in 2016 finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. The EPA also promulgated pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations to municipal sewage treatment plants. Environmental groups have encouraged the EPA to supplement those requirements. Various members of Congress likewise have from time to time introduced bills that would result in more stringent control or outright bans of the hydraulic fracturing process.

In addition, the Department of the Interior promulgated regulations concerning the use of hydraulic fracturing on lands under its jurisdiction, which includes lands on which we conduct or plan to conduct operations. While the Trump Administration rescinded those rules, that decision is being challenged in court. Regardless of how the federal issues are eventually resolved, states have been imposing new restrictions or bans on hydraulic fracturing. Even local jurisdictions, such as Denton, Texas and several cities in Colorado, have adopted, or tried to adopt, regulations restricting hydraulic fracturing. Additional hydraulic fracturing requirements at the federal, state or local level may limit our ability to operate or increase our operating costs.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through permitting programs and the imposition of other requirements. In addition, the EPA has developed and may continue to develop stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and natural gas production. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants.

In 2012 and 2016, the EPA issued air regulations for the oil and natural gas industry that address emissions from certain new sources of volatile organic compounds, sulfur dioxide, air toxics, and methane. The rules included the first federal air standards for natural gas and oil wells that are hydraulically fractured, or refractured, as well as requirements for other processes and equipment, including storage tanks. Although the EPA later made technical amendments to reduce the regulatory burden of the 2012 and 2016 rules, compliance has imposed additional requirements and costs on our operations.

In October 2015, the EPA announced that it was lowering the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion. Implementation has been ongoing and has resulted in expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas could be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

Climate Change

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response, governments increasingly have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, the Kyoto Protocol and the Paris Agreement address greenhouse gas emissions, and several countries, including those comprising the European Union, have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have been implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emissions targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration took a variety of steps to address climate change. For example, the EPA issued regulations requiring us and other companies to annually report certain greenhouse gas emissions from oil and natural gas facilities. Beyond its measuring and reporting rules, the EPA issued an "Endangerment Finding” under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step in issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities.

In addition, the Obama Administration developed a Strategy to Reduce Methane Emissions that was intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels.

Consistent with that strategy, the EPA issued air rules for oil and gas production sources, and the federal Bureau of Land Management (BLM) promulgated standards for reducing venting and flaring on public lands.

The Trump Administration tried to roll back many of the Obama-era climate change policies and rules. But shortly after his inauguration, President Biden accepted the Paris Agreement on behalf of the United States, declared climate considerations an essential part of the United States' foreign policy, issued a moratorium on new oil and gas leases on federal lands, and directed federal agencies to incorporate climate change considerations in their operations. Thus, new federal programs relating to climate change appear to be likely through at least 2024.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and reduce demand for our products.

The National Environmental Policy Act

Oil and natural gas exploration and production activities may be subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and other natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and other natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act and the Clean Water Act. The United States Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or other natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties may result.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration's hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees.

Human Capital

Employees

At Battalion, our success is delivered through our highly capable and diverse workforce. Our team is comprised of individuals with extensive technical, industry and other professional experience. By recruiting, hiring and retaining an experienced and diverse team, we are able to leverage years of experience, new ideas and problem solving in a collaborative environment. As of December 31, 2021, we had 58 full-time employees. We also engage the services of independent contractors and consultants along with certain professional service firms to support our work in specific areas. We have no collective bargaining agreements with our employees. We believe that we have good relations with our employees.

Driving and Supporting a Safety First Culture

The safety of our employees, contractors and the communities in which we operate is one of our most critical responsibilities. We believe that driving a safety culture requires daily prioritization and includes a multi-faceted approach to provide our employees with the tools, support, education and incentives to operate safely:

- All employees, contractors and consultants performing work in the field participate in ongoing environmental, health and safety engagements including training, routine meetings, and individual coaching;
- Work stop authority – all of our employees and contractors have a responsibility to intercede and stop observed high hazard activities or conditions without proper controls;
- Policies and procedures implemented to support a safe working environment; and
- Environmental and safety metrics measuring performance linked to compensation.

Our employees and contractors are educated on the risks inherent in our operations and are equipped with the tools necessary to ensure they can operate safely.

COVID-19 Response

In response to the COVID-19 pandemic, we implemented changes to ensure the health and safety of our employees and the communities where we operate. We complied with the guidelines published by the Centers for Disease Control or mandated by local authorities. We implemented work from home arrangements for our staff employees and additional safety measures for those continuing critical on-site work in the field including social distancing, masks, testing, self-reporting and procedures for those testing positive.

Compensation and Benefits

We have designed our compensation program to attract and retain talented employees with the requisite knowledge and experience. We offer market-competitive compensation programs, as well as strong health and welfare benefits along with a competitive 401(k) program. We have designed paid time off policies to allow our employees time off for family and other priorities. We have operational and financial metrics tied to our short-term incentives that align with our business strategy and the interests of our stockholders.

Diversity and Inclusion

We believe all employees should be treated fairly and valued in our organization. Diversity of thoughts and experiences allows us to identify the best solutions within our company. All Battalion employees must act in accordance with our Employee Handbook, which is inclusive of our Code of Conduct. The Employee Handbook covers various topics including, among others, policies prohibiting harassment, discrimination and retaliation and policies covering workplace anti-violence, cybersecurity, confidential information and conduct. On an annual basis, employees are required to acknowledge and agree to abide by these policies.

Principal Office

As of December 31, 2021, we leased corporate office space in Houston, Texas at 3505 West Sam Houston Parkway North.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Securities Exchange Act of 1934, as amended. We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Forms 3, 4 and 5 filed on behalf of directors and officers, and any amendments to such reports, available free of charge through our corporate website at *www.battalionoil.com* as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. In addition, our insider trading policy, regulation FD policy, corporate governance guidelines, code of conduct, code of ethics, audit committee charter, compensation committee charter, nominating and corporate governance committee charter and reserves committee charter are available on our website under the heading "Investors—Corporate Governance". Within the time period required by the SEC and the NYSE, as applicable, we will post on our website any modifications to the code of conduct and the code of ethics for our chief executive officer and senior financial officers and any waivers applicable to senior officers as defined in the applicable code, as required by the Sarbanes-Oxley Act of 2002. In addition, our reports, proxy and information statements, and our other filings are also available to the public over the internet at the SEC's website at *www.sec.gov*. Unless specifically incorporated by reference in this Annual Report on Form 10-K, information that you may find on our website is not part of this report.

ITEM 1A. RISK FACTORS

COVID-19 Risk Factors

Events beyond our control, including a global or domestic health crisis, may result in unexpected adverse operating and financial results.

In 2020, in response to the novel coronavirus (COVID-19) pandemic governments around the world, including U.S. federal and state governments, imposed restrictions intended to limit the extent and spread of the virus, including travel restrictions, quarantines and business closures. The COVID-19 outbreak and governmental restrictions significantly impacted economic activity and markets and dramatically reduced current and anticipated demand for oil and natural gas, adversely impacting the prices we receive for our production, resulting in us temporarily shutting in producing wells. During 2021, widespread availability of COVID-19 vaccines in the United States and elsewhere combined with accommodative governmental monetary and fiscal policies and other factors, led to a rebound in demand for oil and natural gas and increases in oil and natural gas prices. However, there remains the potential for demand for oil and natural gas to be adversely impacted by the economic effects of the ongoing COVID-19 pandemic, including as a consequence of the circulation of more infectious "variants" of the disease, vaccine hesitancy, waning vaccine effectiveness or other factors. As a consequence, we are unable to predict the impact of these factors which may negatively impact our business in numerous ways, including, but not limited to, the following:

- reducing our revenues if the outbreak results in a substantial or prolonged decrease in demand for oil and natural gas due to an economic downturn or recession;
- disrupting our operations if our employees or contractors are unable to work due to illness or if our field operations are suspended or temporarily shut-down or restricted due to measures designed to contain the outbreak;
- disrupting the operations of our midstream service providers, on whom we rely for the gathering, processing and transportation of our production, due to measures designed to contain the outbreak, and/or the difficult economic environment may lead to capital spending constraints, bankruptcy, the closing of facilities or inability to maintain infrastructure, which may adversely affect our ability to market our production, increase our costs, lower the prices we receive, or result in the shut-in of our producing wells or a delay or discontinuation of our development plans; and
- the disruption and instability in the financial markets and the uncertainty in the general business environment may affect our ability to access capital, monetize assets and successfully execute our plans.

The ongoing COVID-19 pandemic may also have the effect of heightening many of the other risks set forth below. Any of these factors could have a material adverse effect on our business, operations, financial results and liquidity. In 2020, oil and natural gas prices declined to historically low levels and we reduced our planned capital expenditures, delayed our drilling and completion plans and temporarily shut-in some of our producing wells, among other responses. We are unable to predict the ultimate adverse impact of the ongoing COVID-19 on our business, which will continue to depend on numerous evolving factors and future developments, including the length of time that the pandemic continues, its ongoing effect on the demand for oil and natural gas and the response of the overall economy and the financial markets after governmental restrictions are eased.

A financial downturn could negatively affect our business, results of operations, financial condition and liquidity.

Actual or anticipated declines in domestic or foreign economic growth rates, regional or worldwide increases in tariffs or other trade restrictions, turmoil affecting the U.S. or global financial system and markets and a severe economic contraction either regionally or worldwide, resulting from current efforts to contain the ongoing COVID-19 coronavirus or other factors, could materially affect our business and financial condition and impact our ability to finance operations by worsening the actual or anticipated future drop in worldwide oil demand, negatively impacting the price we receive for our oil and natural gas production. Negative economic conditions could also adversely affect the collectability of our trade receivables or performance by our vendors and suppliers or cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations. All of the foregoing may adversely affect our business, financial condition, results of operations and cash flows.

Operational Risk Factors

We are substantially dependent upon our drilling success on our Delaware Basin properties.

We are a pure-play, single-basin operator in the Delaware Basin in West Texas. As a consequence of this geographical concentration, we may have greater exposure to the impact of regional supply and demand factors, delays or interruptions in production from governmental regulation, processing or transportation capacity constraints, market limitations, water shortages, or other conditions adversely impacting our ability to produce or market our production. Such events could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted rates of return.

Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results is dependent upon current and future market prices for our oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost. The costs of drilling and completing a well are often uncertain, and are affected by many factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions; and
- compliance with governmental requirements.

If we are unable to accurately predict and control the costs of drilling and completing a well, we may be forced to limit, delay or cancel drilling operations.

Increasing attention to environmental, social and corporate governance (ESG) matters may impact our business.

Companies conducting oil and natural gas activities, along with companies across other industries, are facing increased scrutiny from stakeholders related to their ESG policies and practices. Stakeholder expectations and standards around ESG are evolving and companies that do not adapt or comply with those expectations and standards, regardless of whether there is a legal requirement to do so, may be adversely impacted. Increased attention to ESG matters may impact our business by increasing costs, reducing demand for oil and natural gas, reducing profits, increasing regulations and litigation, and impending our access to capital or may negatively impact our stock price.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their ESG approaches. Currently, there are no universal standards for scores or ratings; however, the importance of sustainability evaluations is becoming more broadly accepted and utilized by investors and stockholders. Unfavorable ratings or assessment of our ESG practices may lead to negative investor sentiment toward us, which could have a negative impact on our stock price and our access to capital.

We could experience periods of higher costs for various reasons, including due to higher commodity prices, increased drilling activity in the Delaware Basin and trade disputes or inflation that affect the costs of steel and other raw materials that we and our vendors rely upon, which could adversely affect our ability to execute our exploration and development plans on a timely basis and within budget.

Our industry is cyclical. When oil, natural gas and natural gas liquids prices increase, shortages of drilling rigs, equipment, supplies, water or qualified personnel may result. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production, particularly in the Delaware Basin, likewise may increase demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. Cost increases may also result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other materials that we and our vendors rely upon and increases in the cost of services to process, treat and transport our production. Any escalation or expansion of tariffs could result in higher costs and affect a greater range of materials we rely upon in our business. The unavailability or high cost of drilling rigs, pressure pumping equipment, tubulars and other supplies, and of qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment and related services, we may enter into contracts that extend over several months or years. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate enough cash flow from operations or be able to raise sufficient capital to do so. Commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we conduct may not be successful or result in additional proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2021, we owned leasehold interests in approximately 40,400 net acres in the Delaware Basin in West Texas of which approximately 11,100 net acres are undeveloped. Unless production in paying quantities is established on units containing these leases during their terms or unless we pay (to the extent we have the contractual right to pay) delay rentals or obtain other extensions to maintain the leases, these leases will expire. If our leases expire, we will lose our right to develop the related properties. We have no current plans to drill on acreage in other areas outside of our core area of operations.

Our drilling plans are subject to change based upon various factors, many of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, some of our acreage is located in sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and are therefore subject to additional risk of expirations.

Our oil and natural gas activities are subject to various risks that are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in, the prospects in which we have or will acquire an interest. Such risks and hazards include:

- human error, accidents and other events beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, adverse weather events, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
- accidental leaks of natural gas, including gas with high levels of hydrogen sulfide (H2S), and other hydrocarbons or toxic or hazardous materials in the environment as a result of human error or the malfunction of equipment or facilities, which can result in personal injury and loss of life, pollution, damage to equipment and suspension of operations;
- well-on-well interference that may reduce recoveries;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and
- the availability of alternative fuels and the price at which they become available.

Some of these risks may be exacerbated by other risks that we face. For instance, certain of our wells produce high levels of H2S, a highly toxic, naturally-occurring gas frequently associated with oil and natural gas production. Safely handling H2S gas requires highly skilled operations and field personnel as well as specialized infrastructure, treating facilities, disposal facilities, and/or third party sour gas takeaway. If we are unable to attract and retain qualified and highly skilled personnel our ability to effectively manage this and other risks may be adversely impacted. Additionally, if we are unable to successfully operate our specialized treating facilities or secure adequate sour gas takeaway capacity from third parties when and if necessary, our ability to effectively manage the H2S levels we see in our natural gas production may be adversely impacted. As a result, our production, revenues, operating costs and liabilities and expenses may be materially and adversely affected and may differ materially from those anticipated by us.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems available in our operating areas, it may be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks or trains to transport our production, which is more expensive and less efficient than transportation via pipeline. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions, the availability and cost of capital, public opposition, regulatory restrictions and judicial challenges. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently expect, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of weather conditions (which may worsen due to climate changes), accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Our strategy involves drilling in shale formations, using horizontal drilling and modern completion techniques. The results of our drilling program using these techniques may be subject to more uncertainties than conventional drilling programs. These uncertainties could result in an inability to meet our expectations for reserves and production.

The drilling of long horizontal laterals and the use of modern completion techniques with multi-stage fracture stimulation in shale formations involves certain risks and complexities that do not exist in conventional wells. Such risks include, but are not limited to, landing the horizontal wellbore in the desired drilling zone, maintaining the desired drilling zone while drilling horizontally through the wellbore formation, running casing through the full span of the wellbore, and being able to run tools and other necessary equipment consistently throughout the horizontal wellbore. Additionally, horizontal drilling and completion techniques may result in faster production decline rates relative to conventional drilling methods. The ultimate success of our drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

If our drilling results are less than anticipated, our investment in these areas may not be as attractive as we anticipate and could result in material write-downs of unevaluated properties and future declines in the value of our undeveloped acreage.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Financial and Liquidity Risk Factors

Oil and natural gas prices are volatile, and low prices could have a material adverse impact on our business.

Our revenues, profitability, future growth and the carrying value of our properties depend substantially on prevailing oil and natural gas prices. Prices also affect the amount of cash flow we have available for capital expenditures and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties.

Oil and natural gas prices are volatile. Among the factors that affect volatility are:

- domestic and foreign supplies of oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries and other oil exporting countries, including Russia, to agree upon and maintain production quotas;
- social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or terrorist attacks;
- the level of consumer demand for oil and natural gas, including demand growth in developing countries, such as China and India;
- labor unrest in oil and natural gas producing regions;
- weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand for oil and natural gas;
- the price and availability of alternative fuels and energy sources;
- the price and availability of foreign imports and domestic exports; and
- worldwide and regional economic and political conditions impacting the global supply and demand for oil and natural gas, which may be driven by many factors, including health epidemics (such as the current global COVID-19 coronavirus outbreak).

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

We may have difficulty financing our planned capital expenditures which could adversely affect our growth.

Our business requires substantial capital expenditures primarily to fund our drilling program. We may also continue to selectively increase our core acreage position, which would require capital in addition to the capital necessary to drill on our existing acreage. It is possible that we will acquire acreage in other areas that we believe are prospective for oil and natural gas production and expend capital to develop such acreage. We expect to use borrowings under our Term Loan Agreement and proceeds from potential future capital markets transactions, if necessary, and which may be difficult or limited to access, to fund capital expenditures that are in excess of our operating cash flow and cash on hand.

Our Term Loan Agreement limits our borrowings. As of December 31, 2021, our Term Loan Agreement had an initial borrowing availability of $200.0 million. As of December 31, 2021, we had $200.0 million of indebtedness outstanding, approximately $0.3 million of letters of credit outstanding and approximately $35.0 million in delayed draw term loans available to be drawn under our Term Loan Agreement, subject to the satisfaction of certain conditions defined in the agreement. Under the Term Loan Agreement, we are required to make scheduled amortization payments in the aggregate amount of $120.0 million from the fiscal quarter ending March 31, 2023 through the fiscal quarter ending September 30, 2025. Our Term Loan Agreement also contains certain financial covenants, including the maintenance of (i) an Asset Coverage Ratio, (ii) a Total Net Leverage Ratio and (iii) a Current Ratio, each as defined in the Term Loan Agreement. We have periodically sought amendments to the covenants under our revolving credit agreements, including the financial covenants, where we have anticipated difficulty in maintaining compliance. In the event we have difficulty in the future meeting the covenants under our Term Loan Agreement, we would be required to seek additional relief, and there is no assurance that it would be granted. Failure to comply with the covenants in our Term Loan Agreement may limit our ability to borrow, result in an event of default and cause amounts outstanding under our Term Loan Agreement to become immediately due and payable.

Additionally, certain segments of the investor community have developed negative sentiment towards investing in our industry, with some investors and investment advisors adopting policies negatively impacting investment in the oil and gas sector based on social and environmental considerations. Commercial and investment banks have also come under pressure to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could potentially result in a reduction of available capital funding for development projects, thus impacting future financial results.

If borrowings under our Term Loan Agreement become insufficient and we are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our drilling, development, land acquisitions and other activities, which could result in a decrease in our production of oil and natural gas, forfeiture of leasehold interests if we are unable or unwilling to renew them, and the sale of some of our assets on an unfavorable basis, each of which could have a material adverse effect on our results and future operations.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Our future oil and natural gas reserves and production and, therefore, our cash flows and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition, results of operations and cash flows.

Historically, we have had substantial indebtedness and we may incur substantially more debt in the future. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We have approximately $200.1 million principal amount of debt, including current portions, as of December 31, 2021. As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, and outstanding principal beginning in the fiscal quarter ending March 31, 2023, which will reduce the amount of cash flow we will have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes or adverse developments in our business or economic downturns impacting the industry in which we operate. Indebtedness under our Term Loan Agreement is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have hedging arrangements that are effective in offsetting interest rate fluctuations. Currently, borrowings under our Term Loan Agreement bear interest at a margin over LIBOR. Financial regulators are working to transition away from LIBOR as a benchmark, and in March 2021, confirmed that the publication of the one-week and two-month LIBOR would cease after December 31, 2021, and all remaining LIBOR tenors will cease after June 30, 2023. If a published LIBOR rate is unavailable, the interest rate on our Term Loan Agreement will be determined using another applicable reference rate and the impact on our borrowing costs, if any, under the alternative rate is uncertain and could have an adverse effect on our cash flows.

We may incur substantially more debt in the future. At December 31, 2021, we had approximately $35.0 million of delayed draw term loans available to be drawn under our Term Loan Agreement, subject to the satisfaction of certain conditions defined in the agreement. Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional shares of common or preferred stock on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.

This Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves. The process of estimating oil and natural gas reserves in accordance with SEC requirements is complex, involving significant estimates and assumptions in the evaluation of available geological, geophysical, engineering and economic data. Accordingly, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The estimates of our reserves as of December 31, 2021 are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, in accordance with SEC requirements, estimates of oil and gas reserves, future net revenue from proved reserves and the present value of our oil and gas properties are based on the assumption that future oil and gas prices remain the same as the 12-month first-day-of-the-month average oil and gas prices for the year ended December 31, 2021. Average prices for oil and natural gas for the 12-month period were as follows: WTI crude oil spot price of $66.55 per Bbl, adjusted by lease or field for quality, transportation fees, and market differentials and a Henry Hub natural gas spot price of $3.60 per MMBtu, adjusted by lease or field for energy content, transportation fees, and market differentials. Any significant variance in the actual future prices from these assumptions could materially affect the estimated quantity and value of our reserves set forth in this report.

In addition, at December 31, 2021, approximately 56% of our estimated proved reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Estimated proved reserves as of December 31, 2021 assume that we will make future capital expenditures of approximately $540.6 million in the aggregate primarily from 2022 through 2026, which are necessary to develop and realize the value of proved reserves on our properties. The estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations, however, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

We are subject to various contractual limitations that affect the discretion of our management in operating our business.

Our Term Loan Agreement contains various provisions that may limit our management's discretion in certain respects. In particular, the Term Loan Agreement limits our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase shares of our common stock and any other capital stock we may issue;
- make loans to others;
- make investments;
- incur additional indebtedness;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- increase our exposure to commodity price fluctuations;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

Compliance with these and other limitations may limit our ability to operate and finance our business and engage in certain transactions in the manner we might otherwise. In addition, if we fail to comply with the limitations under our Term Loan Agreement, our creditors, to the extent the agreement so provides, may accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us.

Federal legislation and rulemaking could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act also establishes margin requirements and certain transaction clearing and trade execution requirements. The Dodd-Frank Act may require us to comply with margin requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The counterparties to our derivative instruments may also spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd-Frank Act and any new regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing commodity derivative contracts. If we reduce our use of derivatives as a consequence, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our financial position, results of operations and cash flows.

Our ability to use net operating loss carryforwards and realized built in losses to offset future taxable income for U.S. federal income tax purposes is subject to limitation.

In general, under Section 382 of the Internal Revenue Code of 1986, as amended, a corporation that undergoes an "ownership change" is subject to limitations on its ability to utilize its pre-change net operating losses (NOLs), and realized built in losses (RBILS), to offset future taxable income. In general, an ownership change occurs if the aggregate stock ownership of certain stockholders (generally 5% stockholders, applying certain look-through rules) increases by more than 50 percentage points over such stockholders' lowest percentage ownership during the testing period (generally three years).

We experienced ownership changes in December 2018 and October 2019 and we may experience additional ownership changes in the future. Limitations imposed on our ability to use NOLs and RBILS to offset future taxable income may cause U.S. federal income taxes to be paid earlier than otherwise would be paid if such limitations were not in effect and could cause such NOLs and RBILS to expire unused, in each case reducing or eliminating the benefit of such NOLs and RBILS. Similar rules and limitations may apply for state income tax purposes.

We may be required to take non-cash asset write-downs.

We may be required under full cost accounting rules to write-down the carrying value of oil and natural gas properties if oil and natural gas prices decline or if there are substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. We utilize the full cost method of accounting for oil and natural gas exploration and development activities. Under full cost accounting, we are required by SEC regulations to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or "ceiling," of the book value of oil and natural gas properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges when hedge accounting is applied, calculated using the unweighted arithmetic average of the first day of each month for the 12-month period ending at the balance sheet date. If the net book value of oil and natural gas properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds the ceiling limitation, SEC regulations require us to impair or "write-down" the book value of our oil and natural gas properties.

During the year ended December 31, 2020, we recorded cumulative full cost ceiling impairments of $215.1 million, primarily driven by a decline in the average pricing used in the valuation of our reserves. As ceiling test computations depend upon the calculated unweighted arithmetic average prices, it is impossible to predict the likelihood, timing and magnitude of any future impairments. Depending on the magnitude, a ceiling test write-down could negatively affect our results of operations.

Costs associated with unevaluated properties, which were approximately $64.3 million at December 31, 2021, are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to depletion and the ceiling test limitation.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas, and natural gas liquids production and comply with the requirements of our Term Loan Agreement, we have entered into oil and natural gas hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile commodity prices, such transactions may limit our potential gains and increase our potential losses if commodity prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production; or

- the counterparties to our hedging agreements fail to perform under the contracts.

Investment in Securities Risk Factors

There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.

Funds advised by Luminus Management, LLC, Oaktree Capital Management, LP and LSP Investment Advisors, LLC, held approximately 37.7%, 24.4% and 14.5%, respectively, of our common stock as of March 3, 2022. Circumstances may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures or other transactions, including the issuance of additional equity securities or debt, that, in their judgment, could enhance their investment in us or another company in which they invest. Such transactions might adversely affect us or other holders of our common stock. In addition, our significant concentration of share ownership may adversely affect the trading price of our common shares because investors may perceive disadvantages in owning shares in companies with significant stockholders.

Future sales of our common stock in the public market or the issuance of securities senior to our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and our ability to raise funds in stock offerings.

A large percentage of our shares of common stock are held by a relatively small number of investors. Sales by us or our stockholders of a substantial number of shares of our common stock in the public markets, or even the perception that these sales might occur, could cause the market price of our common stock to decline or could impair our ability to raise capital through a future sale of, or pay for acquisitions using, our equity securities.

We are currently authorized to issue 100.0 million shares of common stock and 1.0 million shares of preferred stock, with such designations, rights, preferences, privileges and restrictions as determined by the Board. As of March 3, 2022, we had outstanding approximately 16.3 million shares of common stock, and warrants, options and restricted stock units to purchase or receive an aggregate of 8.1 million shares of our common stock. As of March 3, 2022, we have also reserved an additional 0.5 million shares for future issuance to our directors, officers and employees under our 2020 Long-Term Incentive Plan. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock.

We may issue common stock or other equity securities senior to our common stock in the future for a number of reasons, including to finance acquisitions, to adjust our leverage ratio, and to satisfy our obligations upon the exercise of warrants and options, or for other reasons. We cannot predict the effect, if any, that future sales or issuances of shares of our common stock or other equity securities, or the availability of shares of common stock or such other equity securities for future sale or issuance, will have on the trading price of our common stock.

Regulatory Risk Factors

We are subject to complex federal, state, local and other laws and regulations that frequently are amended to impose more stringent requirements that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our activities, we may not be able to conduct our operations as planned. We also may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;

- reports concerning operations;
- air quality, air emissions, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- pipeline construction;
- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with applicable laws may result in the suspension or termination of operations and subject us to liabilities, including administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, the laws governing our operations or the enforcement thereof could change in ways that substantially increase our costs of doing business. For example, negative public perception regarding us and/or our industry may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations.

Under environmental, health and safety laws and regulations, we also could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages including the assessment of natural resource damages. Such laws may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling and pipeline projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to regulation by oil and natural gas producing states relating to conservation practices and protection of correlative rights. Such regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. By way of example, in 2015 the EPA lowered the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion. Implementation eventually could result in more stringent emissions controls and additional permitting obligations for our operations.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Federal, state and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we currently conduct operations, or may in the future, plan to conduct operations. Consequently, we could be subject to additional levels of regulation, operational delays or increased operating costs and could have additional regulatory burdens imposed upon us that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

From time to time, for example, legislation has been proposed in Congress to require more stringent federal control or outright bans of hydraulic fracturing. Further, the EPA issued a study in 2016 finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. Other governmental reviews have also been conducted that focus on environmental aspects of hydraulic fracturing. Such activities eventually could result in additional regulatory scrutiny that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Certain states, including Texas where we conduct our operations, likewise are considering or have adopted more stringent requirements for various aspects of hydraulic fracturing operations, such as permitting, disclosure, air emissions, well construction, seismic monitoring, waste disposal and water use. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have extended to bans on hydraulic fracturing.

The proliferation of regulations may limit our ability to operate. If the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response, governments increasingly have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, the Kyoto Protocol and the Paris Agreement address greenhouse gas emissions, and international negotiations over climate change and greenhouse gases are continuing. Meanwhile, several countries, including those comprising the European Union, have established greenhouse gas regulatory systems.

In the United States, many states, either individually or through multi-state regional initiatives, have been implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emission targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration addressed climate change through a variety of administrative actions. The EPA thus issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. Beyond measuring and reporting, the EPA issued an "Endangerment Finding” under section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, then President Obama released a Strategy to Reduce Methane Emissions that included consideration of both voluntary programs and targeted regulations for the oil and gas sector. Consistent with that strategy, the EPA issued final rules in 2016 for new and modified oil and gas production sources (including hydraulically fractured oil wells, natural gas well sites, natural gas processing plants, natural gas gathering and boosting stations and natural gas transmission sources) to reduce emissions of methane as well as volatile organic compound and toxic pollutants. In addition, the BLM promulgated standards for reducing venting and flaring on public lands.

The Trump Administration tried to roll back many of the Obama-era climate change policies and rules. But shortly after his inauguration, President Biden accepted the Paris Agreement on behalf of the United States, declared climate considerations an essential part of the United States’ foreign policy, issued a moratorium on new oil and gas leases on federal lands, and directed federal agencies to incorporate climate change considerations in their operation. Thus, new federal programs relating to climate change appear to be likely through at least 2024.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that cause or contribute to significant greenhouse gas emissions. Such cases may seek emissions reductions, challenge air emissions or other permits or request damages for alleged climate change impacts to the environment, people, and property.

Any new initiatives that may be adopted to reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand for our products.

Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner.

Water is an essential component of our drilling and hydraulic fracturing processes. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, natural gas liquids and natural gas, which could have an adverse effect on our business, financial condition and results of operations. Wastewaters from our operations typically are disposed of via underground injection. Some studies have linked earthquakes in certain areas to underground injection, which is leading to greater public scrutiny and regulation of disposal wells. Any new environmental initiatives or regulations that restrict injection of fluids, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas, or that limit the withdrawal, storage or use of surface water or ground water necessary for hydraulic fracturing of our wells, could increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations and cash flows.

Cybersecurity Risk Factors

We depend on computer, telecommunications and information technology systems to conduct our business, and failures, disruptions, cyber-attacks or other breaches in data security could significantly disrupt our business operations, create liability and increase our costs.

The oil and natural gas industry in general has become increasingly dependent upon technology to conduct day-to-day operations, including certain exploration, development and production activities. We have agreements with third parties for hardware, software, telecommunications and other information technology services necessary to our business and have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. We use these systems and data to, among other things, estimate quantities of oil, natural gas liquids and natural gas reserves, process and record financial data and communicate with our employees and third parties. Failures in these systems due to hardware or software malfunctions, computer viruses, natural disasters, fire, human error or other causes could significantly affect our ability to conduct our business. In particular, cyber-security attacks on systems are increasing in frequency and sophistication and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to them, there can be no assurance that these procedures and controls will be sufficient to prevent security threats from materializing and any interruptions to our arrangements with third parties, to our computing and communications infrastructure or our information systems could significantly disrupt our business operations. Further, the loss or corruption of sensitive information could have a material adverse effect on our reputation, financial position, results of operations or cash flows. In addition, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks. We generally do not maintain insurance coverage for the costs associated with cyber-security events.

Risk Factors Relating to Our Prior Restructuring

Our actual financial results may vary materially from the projections that we filed with the bankruptcy court in connection with the confirmation of our plan of reorganization.

In connection with the disclosure statement we filed with the bankruptcy court, and the hearing to consider confirmation of our plan of reorganization, we prepared projected financial information to demonstrate to the bankruptcy court the feasibility of the plan of reorganization and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance and with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. As a result, investors should not rely on these projections.

Our historical financial information may not be indicative of our future financial performance.

Our capital structure was significantly altered under the plan of reorganization. We adopted fresh-start accounting effective October 1, 2019, as an accounting convenience date to coincide with the timing of our normal fourth quarter reporting, and as a result, our assets and liabilities were adjusted to fair values and our accumulated deficit was restated to zero. Further, as a result of the implementation of our plan of reorganization and the transactions contemplated thereby, our historical financial information may not be indicative of our future financial performance. Accordingly, our financial condition and results of operations following our emergence from chapter 11 are not comparable to the financial condition and results of operations reflected in our historical financial statements.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1. *Business* and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 10*, "Commitments and Contingencies,"* and is incorporated herein by reference.

Under rules promulgated by the SEC, administrative or judicial proceedings arising under any federal, state or local provisions that have been enacted or adopted regulating the discharge of materials into the environment or primarily for the purpose of protecting the environment are disclosed if the governmental authority is party to such proceeding and the proceeding involves potential monetary sanctions of $300,000 or more. We are not party to any such proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

On February 20, 2020, our common stock commenced trading on the NYSE American exchange under the symbol "BATL." Previously, on July 22, 2019, we were notified by the New York Stock Exchange (NYSE) that due to "abnormally low" trading price levels, pursuant to Section 802.01D of the NYSE Listed Company Manual, the NYSE determined to commence delisting proceedings to delist our Predecessor common stock under the symbol "HK" and warrants exercisable for common stock. Trading in our securities was suspended on July 22, 2019. On July 23, 2019, our Predecessor common stock commenced trading on the OTC Pink marketplace under the symbols "HKRS" and "HKRSQ." On October 8, 2019, upon emergence from chapter 11 bankruptcy, all existing shares of our Predecessor common stock were cancelled and we, as the Successor Company, issued approximately 16.2 million shares of new common stock which traded on the OTC Pink marketplace under the symbol "HALC" until we listed on the NYSE American under "BATL."

We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including our prospects, and such other factors, as the board of directors deems relevant. We are also restricted from paying cash dividends on common stock under our Term Loan Agreement.

Approximately 55 registered stockholders of record as of March 3, 2022 held our common stock. In most instances, a registered stockholder holds shares in street name for one or more customers who beneficially own the shares.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

None.

ITEM 6. RESERVED

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Overview

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. During 2017, we acquired certain properties in the Delaware Basin and divested our assets located in the Williston Basin in North Dakota and in the El Halcón area of East Texas. As a result, our properties and drilling activities are currently focused in the Delaware Basin, where we have an extensive drilling inventory that we believe offers attractive economics.

At December 31, 2021, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell), using Securities and Exchange Commission (SEC) prices for crude oil and natural gas, which are based on preceding 12-month first day of the month average prices of West Texas Intermediate (WTI) crude oil spot price of $66.55 per Bbl and Henry Hub natural gas spot price of $3.60 per MMBtu, were approximately 95.9 MMBoe, consisting of 58.7 MMBbls of oil, 16.3 MMBbls of natural gas liquids, and 125.0 Bcf of natural gas. Approximately 44% of our proved reserves were classified as proved developed as of December 31, 2021. We maintain operational control of 99.9% of our proved reserves. Substantially all of our proved reserves and production at December 31, 2021 are associated with our Delaware Basin properties.

Our total operating revenues for the year ended December 31, 2021 were approximately $285.2 million, compared to total operating revenues for the year ended December 31, 2020 of approximately $148.3 million. The increase in revenues is primarily attributable to an approximate $24.14 per Boe increase in average realized prices (excluding the effects of hedging arrangements). Full year 2021 production averaged 16,241 Boe/d compared to average daily production of 16,858 Boe/d for 2020. Average daily oil and natural gas production was impacted by the temporary shut-in of production amounting to approximately 300 Boe/d and 1,300 Boe/d for the year ended December 31, 2021 and 2020, respectively. In February 2021, we temporarily shut-in production due to inclement weather. In May and June 2020, we temporarily shut-in production in response to historically low commodity prices. Current year production was also impacted by third-party processing curtailments and downtime resulting from facility upgrades and repairs.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, transportation take-away capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

In 2021, we spent approximately $52.6 million on oil and gas capital expenditures. In early 2021 and at the end of 2021, we ran one operated rig in the Delaware Basin. We drilled and cased 2.0 gross (2.0 net) operated wells, completed 6.0 gross (6.0 net) operated wells, and put online 6.0 gross (6.0 net) operated wells during the year.

We expect to spend approximately $130.0 million to $150.0 million on capital expenditures during 2022. Overall, we currently plan to drill 12 gross operated wells during the year, complete 9 to 13 gross operated wells, and bring 8 to 12 gross operated wells on production. Our 2022 capital budget currently contemplates running one operated rig in the Delaware Basin during the year. We continuously monitor changes in market conditions and adapt our operational plans as necessary in order to maintain financial flexibility, preserve core acreage and meet contractual obligations, and therefore our capital budget is subject to change.

We expect to fund our budgeted 2022 capital expenditures with cash and cash equivalents on hand from the funding of the Term Loan Agreement and cash flows from operations. In the event our cash flows are materially less than anticipated or our costs are materially greater than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may be required to curtail drilling, development, land acquisitions and other activities to reduce our capital spending. However, significant or prolonged reductions in capital spending will adversely impact our production and may negatively affect our future cash flows.

Oil and natural gas prices are inherently volatile and sustained lower commodity prices could have a material impact upon our full cost ceiling test calculation. The ceiling test calculation dictates that we use the unweighted arithmetic average price of crude oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. Using the first-day-of-the-month average for the 12-months ended March 31, 2022 of the WTI crude oil spot price of $75.28 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first-day-of-the-month average for the 12-months ended March 31, 2022 of the Henry Hub natural gas price of $4.09 per MMBtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials, our ceiling test calculation would not have generated an additional impairment at December 31, 2021, holding all other inputs and factors constant. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties to our full cost pool, capital spending and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Recent Developments

Risk and Uncertainties

We are continuously monitoring the current and potential impacts of the novel coronavirus (COVID-19) pandemic on our business, including how it has and may continue to impact our operations, financial results, liquidity, contractors, customers, employees and vendors, and taking appropriate actions in response, including implementing various measures to ensure the continued operation of our business in a safe and secure manner. In 2020, COVID-19 and governmental actions to contain the pandemic contributed to an economic downturn, reduced demand for oil and natural gas and, together with a price war involving the Organization of Petroleum Exporting Countries (OPEC)/Saudi Arabia and Russia, depressed oil and natural gas prices to historically low levels. Although OPEC and Russia subsequently agreed to reduce production, downward pressure on prices continued for several months, particularly given concerns over the impacts of the current economic downturn on demand. As a consequence, beginning March 2020, we realized lower revenue as a result of commodity price declines, resulting in us temporarily shutting in producing wells in May and June 2020, which further contributed to lower revenues that year. Additionally in 2020, we incurred ceiling test impairments, which were primarily driven by a decline in the average pricing required to be used in the valuation of our reserves for ceiling test purposes.

During 2021, widespread availability of COVID-19 vaccines in the United States and elsewhere combined with accommodative governmental monetary and fiscal policies and other factors, led to a rebound in demand for oil and natural gas and increases in oil and natural gas prices. Further, at present, OPEC and Russia have been coordinating production increases to maintain supply and demand balance, stabilize prices and avoid market disruptions. However, there remains the potential for such cooperation to fail and for demand for oil and natural gas to be adversely impacted by the economic effects of the ongoing COVID-19 pandemic, including as a consequence of the circulation of more infectious "variants" of the disease, vaccine hesitancy, waning vaccine effectiveness or other factors. As a consequence, we are unable to predict whether oil and natural gas prices will remain at current levels or will be adversely impacted by the same sorts of factors that negatively impacted prices during 2020. Furthermore, the health of our employees, contractors and vendors, and our ability to meet staffing needs in our operations and critical functions remain concerns and cannot be predicted, nor can the impact on our customers, vendors and contractors. Any material effect on these parties could adversely impact us. These and other factors could affect our operations, earnings and cash flows and could cause our results to not be comparable to those of the same period in previous years. The results presented in this Form

10-K are not necessarily indicative of future operating results. For further information regarding the actual and potential impacts of COVID-19 on us, see *"Risk Factors"* in Item 1A of this Annual Report on Form 10-K.

Term Loan Credit Facility

On November 24, 2021, we and our wholly owned subsidiary, Halcón Holdings, LLC (Borrower), entered into an Amended and Restated Senior Secured Credit Agreement (Term Loan Agreement) with Macquarie Bank Limited, as administrative agent, and certain other financial institutions party thereto, as lenders. The Term Loan Agreement amends and restates in its entirety our Senior Credit Agreement as discussed below. Pursuant to the Term Loan Agreement, the lenders have agreed to loan us (i) $200.0 million, which funded on November 24, 2021 and was partially used to refinance all amounts owed under the Senior Credit Agreement; (ii) up to $20.0 million, available to be drawn up to 18 months from November 24, 2021, subject to the satisfaction of certain conditions; and (iii) up to $15.0 million, which amount will be available to be drawn from the date certain wells included in the approved plan of development are deemed producing, subject to the satisfaction of certain conditions. An additional $5.0 million is available for the issuance of letters of credit. The maturity date of the Term Loan Agreement is November 24, 2025. Until such maturity date, borrowings under the Term Loan Agreement shall bear interest at a rate per annum equal to LIBOR (or another applicable reference rate, as determined pursuant to the provisions of the Term Loan Agreement) plus an applicable margin of 7.00%. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 6, *"Debt"* for additional information on the Term Loan Agreement.

Senior Revolving Credit Facility

On November 24, 2021, our Senior Secured Revolving Credit Agreement (Senior Credit Agreement) was amended and restated in its entirety by the Term Loan Agreement. Borrowings outstanding under the Senior Credit Agreement were repaid with proceeds from the Term Loan Agreement resulting in a charge of $0.1 million presented in *"Gain (loss) on extinguishment of debt"* in the consolidated statements of operations for the year ended December 31, 2021.

On September 24, 2021, we entered into the Fifth Amendment to Senior Secured Revolving Credit Agreement (the Fifth Amendment) which, among other things, modified the limits on swap agreements so as not to exceed, (i) from the period of the Fifth Amendment effective date through December 31, 2021, the percentage of the reasonably anticipated hydrocarbon production from proved developed producing reserves during such period hedged pursuant to secured swap agreements in place as of the Fifth Amendment effective date; (ii) for the fiscal year ending December 31, 2022, the greater of (a) the proved developed producing reserves during such fiscal year hedged pursuant to secured swap agreements in place as of the Fifth Amendment effective date and (b) 85% of the proved developed producing reserves during such fiscal year; and (iii) for the fiscal years ending December 31, 2023, December 31, 2024 and December 31, 2025, swap agreements not to exceed 85%, 70% and 60% of the proved developed producing reserves, respectively, during each fiscal year.

On May 10, 2021, we entered into the Fourth Amendment to Senior Secured Revolving Credit Agreement (the Fourth Amendment) which reduced the borrowing base to $185.0 million effective June 1, 2021 and further reduced the borrowing base to $175.0 million effective September 1, 2021. The Fourth Amendment also, among other things, (i) increased interest margins to 2.00% to 3.00% for ABR-based loans and 3.00% to 4.00% for Eurodollar-based loans, (ii) amended the covenant relating to the minimum mortgaged total value of proved borrowing base properties to increase the value from 90% to 95%, (iii) provided for direct reductions in the borrowing base in the event of asset dispositions in excess of $1.0 million per fiscal year or swap terminations and (iv) revised certain covenants and covenant-related baskets including, but not limited to, adding covenants prohibiting the designation of unrestricted subsidiaries and requiring prior consent from the lenders regarding asset dispositions or swap terminations in excess of the greater of $7.5 million or 3.5% of the then effective borrowing base.

Paycheck Protection Program Loan

Effective August 13, 2021, the principal amount of our promissory note (the PPP Loan) under the Paycheck Protection Program of the Coronavirus Aid, Relief and Economic Security Act (the CARES Act) was reduced from $2.2 million to $0.2 million by the U.S. Small Business Administration (SBA). We applied for forgiveness of the amount due on the PPP Loan based on the use of the loan proceeds on eligible expenses in accordance with the terms of the CARES Act. We recorded a gain on the extinguishment of the forgiven portion of the PPP Loan and related accrued interest of $2.1 million. The gain is presented in *"Gain (loss) on extinguishment of debt"* in the consolidated statements of operations for the year ended December 31, 2021.

Employee Retention Credit

The CARES Act included, among other things, provisions relating to refundable payroll tax credits (the Employee Retention Credit or ERC). As provided for in the CARES Act and subsequent legislation which modified and extended the provisions included therein, the ERC allows for a refundable tax credit against certain employment taxes equal to 50% of the first $10,000 in qualified wages paid to each employee after March 12, 2020 and through December 31, 2020 and 70% of the first $10,000 in qualified wages paid to each employee, per calendar quarter, after December 31, 2020 through September 30, 2021. During the year ended December 31, 2021, we determined that the qualifications for the Employee Retention Credit were met and filed the corresponding applications for the applicable 2020 and 2021 periods. We recognized an approximate $0.7 million Employee Retention Credit during the year ended December 31, 2021, with approximately $0.5 million recorded to *"General and administrative"* and approximately $0.2 million recorded to *"Lease operating"* in the consolidated statements of operations.

Capital Resources and Liquidity

In March 2020, the World Health Organization declared the outbreak of COVID-19 a pandemic. In 2020, the COVID-19 outbreak and associated government restrictions significantly impacted economic activity and markets and dramatically demand for oil and natural gas at the same time that supply was maintained at high levels due to a price and market share war involving the OPEC/Saudi Arabia and Russia, all of which adversely impacted the prices we received for our production. As a consequence, beginning in March 2020, we realized lower revenue as a result of these commodity price declines, resulting in us temporarily shutting in producing wells in May and June 2020, which further contributed to lower revenues that year. Additionally in 2020, we incurred ceiling test impairments, which were primarily driven by a decline in the average pricing required to be used in the valuation of our reserves for ceiling test purposes.

During 2021, widespread availability of COVID-19 vaccines in the United States and elsewhere combined with accommodative governmental monetary and fiscal policies and other factors, led to a rebound in demand for oil and natural gas and increases in oil and natural gas prices. Further, at present, OPEC and Russia have been coordinating production increases to maintain supply and demand balance, stabilize prices and avoid market disruptions. However, there remains the potential for such cooperation to fail and for demand for oil and natural gas to be adversely impacted by the economic effects of the ongoing COVID-19 pandemic, including as a consequence of the circulation of more infectious "variants" of the disease, vaccine hesitancy, waning vaccine effectiveness or other factors. As a consequence, we are unable to predict whether oil and natural gas prices will remain at current levels or will be adversely impacted by the same sorts of factors that negatively impacted prices during 2020. Actual or anticipated declines in domestic or foreign economic activity or growth rates, regional or worldwide increases in tariffs or other trade restrictions, turmoil affecting the U.S. or global financial system and markets and a severe economic contraction either regionally or worldwide, resulting from current efforts to contain the COVID-19 coronavirus or other factors, could materially affect our business and financial condition and impact our ability to finance operations by worsening the actual or anticipated future drop in worldwide oil demand, negatively impacting the price received for oil and natural gas production or adversely impacting our ability to comply with covenants in our Term Loan Agreement. Negative economic conditions could also adversely affect the collectability of our trade receivables or performance by our vendors and suppliers or cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations. All of the foregoing may adversely affect our business, financial condition, results of operations, cash flows and, potentially, compliance with the covenants contained in our Term Loan Agreement.

We expect to spend approximately $130.0 million to $150.0 million in capital expenditures, including drilling, completion, support infrastructure and other capital costs, during 2022. Additionally, from time to time, we enter into commitments that may require us to incur material expenditures in the future. Included in our 2022 capital expenditures budget is $2.6 million associated with an active drilling rig commitment. We have a minimum volume commitment with a third party for the treating of sour gas production through June 30, 2022. The future payments associated with the minimum volume commitment are approximately $4.8 million. These capital spending requirements and commitments are expected to be funded with cash and cash equivalents on hand from the funding of our Term Loan Agreement and cash flows from operations. Amounts borrowed under our Term Loan Agreement bear interest at LIBOR plus an applicable margin of 7.00% and will mature on November 24, 2025. At December 31, 2021, we had $46.9 million of cash and cash equivalents, $200.0 million of indebtedness outstanding, approximately $0.3 million letters of credit outstanding and $35.0 million in delayed draw term loans available to be drawn under our Term Loan Agreement, subject to the satisfaction of certain conditions defined in the agreement. We are required to make scheduled amortization payments in the aggregate amount of $120.0 million from the fiscal quarter ending March 31, 2023 through the fiscal quarter ending September 30, 2025. In addition, we may be required to make mandatory prepayments of the loans under the Term Loan Agreement in connection with the incurrence of non-permitted debt, certain asset sales, and with excess cash on hand in excess of certain maximum levels. For each fiscal quarter after January 1, 2023, we shall make mandatory prepayments when the Consolidated Cash Balance, as defined in the Term Loan Agreement, exceeds $20.0 million. Until December 31, 2024, the forecasted APOD capital expenditures for the succeeding fiscal quarter are excluded for purposes of determining the Consolidated Cash Balance.

The Term Loan Agreement contains certain financial covenants, including maintenance of (i) an Asset Coverage Ratio (as defined in the Term Loan Agreement) of not less than (A) 1.50 to 1.00 as of December 31, 2021 and March 31, 2022, (B) 1.60 to 1.00 as of June 30, 2022, (C) 1.70 to 1.00 as of September 30, 2022, and (D) 1.80 to 1.00 as of December 31, 2022 and each fiscal quarter thereafter, (ii) a Total Net Leverage Ratio (as defined in the Term Loan Agreement) of not greater than (A) 3.25 to 1.00 as of December 31, 2021 through and including June 30, 2022, (B) 3.00 to 1.00 as of September 30, 2022 and December 31, 2022, (C) 2.75 to 1.00 as of March 31, 2023, and (D) 2.50 to 1.00 as of each fiscal quarter thereafter, and (iii) a Current Ratio (as defined in the Term Loan Agreement) of not less than 1.00:1.00, each determined as of the last day of any fiscal quarter period.

Changes in the level and timing of our production, drilling and completion costs, the cost and availability of transportation for our production and other factors varying from our expectations can affect our ability to comply with the covenants under our Term Loan Agreement. As a consequence, we endeavor to anticipate potential covenant compliance issues and work with our lenders to address any such issues ahead of time.

We have periodically, including as recently as October 2020, obtained waivers or amendments to the financial covenants under our revolving credit agreements in circumstances where we anticipated that it might be challenging for us to comply with the financial covenants for a particular period of time. For instance, depressed oil and natural gas prices during 2020 and our decision to temporarily shut-in a portion of our production in response to market conditions adversely impacted our cash flows, which, combined with cash requirements associated with capital-intensive oil and gas development projects undertaken in late 2019 and early 2020, led to challenges in our compliance with the Current Ratio under the Senior Credit Agreement for the fiscal quarter ended June 30, 2020. Thus, on July 31, 2020, we secured a waiver in which the lenders consented to waive maintenance of the Current Ratio (as defined in the Senior Credit Agreement) of not less than 1.00 to 1.00 for the fiscal quarter ended June 30, 2020. In conjunction with the fall 2020 borrowing base redetermination process under the Senior Credit Agreement, and due to a decline in the value associated with our derivative contracts, we pursued additional relief from our lenders in regards to the Current Ratio. On October 29, 2020, in the Third Amendment to the Senior Credit Agreement, the lenders waived maintenance with the Current Ratio for the fiscal quarter ending September 30, 2020 and suspended testing of the Current Ratio until the fiscal quarter ended December 31, 2021. The Senior Credit Agreement was amended and restated by the Term Loan Agreement in November 2021.

Similarly, in prior years, we have also obtained waivers and amendments for other financial covenant violations. For instance, our strategic decision to transform into a pure-play, single basin company focused on the Delaware Basin in West Texas resulted in us divesting our producing properties located in other areas and acquiring primarily undeveloped acreage in the Delaware Basin. Our drilling activities once we acquired these assets required significant capital expenditure outlays to replenish production and related EBITDA from the divested producing properties. These and other factors adversely impacted our ability to comply with our debt covenants under the predecessor credit agreement by reducing our production, reserves and EBITDA on a current and a pro forma historical basis, while making us more susceptible to fluctuations in performance and compliance more challenging. In addition, we encountered certain operational difficulties that impacted our ability to comply, including elevated levels of hydrogen sulfide in the natural gas produced from our Monument Draw wells and limited and expensive treatment and transportation options. Severance payments to executives in 2019 also impacted our ability to comply with our financial covenants.

While we have largely been successful in obtaining modifications of our covenants as needed, there can be no assurance that we will be successful in the future. In the event we are not successful in obtaining covenant modifications, if needed, there is no assurance that we will be successful in implementing alternatives that allow us to maintain compliance with our covenants or that we will be successful in obtaining alternative financing that provides us with the liquidity that we need to operate our business. Even if successful, alternative sources of financing could prove more expensive than borrowings under our Term Loan Agreement.

When commodity prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. While we use derivative instruments to provide partial protection against declines in oil and natural gas prices, the total volumes we hedge are less than our expected production, vary from period to period based on our view of current and future market conditions, remain consistent with the requirements in effect under our Term Loan Agreement and extend, on a rolling basis, for the next four years. These limitations result in our liquidity being susceptible to commodity price declines. Additionally, while intended to reduce the effects of volatile commodity prices, derivative transactions may limit our potential gains and increase our potential losses if commodity prices were to rise substantially over the price established by the hedge. Our hedge policies and objectives may change significantly as our operational profile changes and/or commodities prices change. We do not enter into derivative contracts for speculative trading purposes.

Our future capital resources and liquidity depend, in part, on our success in developing our leasehold interests, growing our reserves and production and finding additional reserves. Cash is required to fund capital expenditures necessary to offset inherent declines in our production and proven reserves, which is typical in the capital-intensive oil and natural gas industry. We strive to maintain financial flexibility while pursuing our drilling plans and may access capital markets, pursue joint ventures, sell assets and engage in other transactions as necessary to, among other things, maintain sufficient liquidity, facilitate drilling on our undeveloped acreage position and permit us to selectively expand our acreage. Our ability to complete such transactions and maintain or increase our liquidity is subject to a number of variables, including our level of oil and natural gas production, proved reserves and commodity prices, the amount and cost of our indebtedness, as well as various economic and market conditions that have historically affected the oil and natural gas industry. Even if we are otherwise successful in growing our proved reserves and production, if oil and natural gas prices decline for a sustained period of time, our ability to fund our capital expenditures, complete acquisitions, reduce debt, meet our financial obligations and become profitable may be materially impacted.

Cash Flow

In 2021, operating cash flows and net borrowings under our credit agreements funded our capital expenditures program. See "*Results of Operations*" for a review of the impact of prices and volumes on operating revenues.

Net increase (decrease) in cash, cash equivalents and restricted cash is summarized as follows (in thousands):

	Years Ended December 31,	
	2021	2020
Cash flows provided by (used in) operating activities	$ 68,572	$ 50,197
Cash flows provided by (used in) investing activities	(51,913)	(72,354)
Cash flows provided by (used in) financing activities	27,405	16,177
Net increase (decrease) in cash, cash equivalents and restricted cash	$ 44,064	$ (5,980)

Operating Activities. Net cash flows provided by operating activities for the year ended December 31, 2021 and 2020 were $68.6 million and $50.2 million, respectively.

Operating cash flows for the year ended December 31, 2021 increased from the prior year due an approximate $24.14 per Boe average realized price increase which contributed to higher total operating revenues in 2021 partially offset by realized losses from derivative contracts incurred in 2021 as a result of increased commodity prices.

Operating cash flows for the year ended December 31, 2020 increased from the prior year due to decreases in our operating expenses associated with our focus on efficiencies and cost savings and a decrease in interest expense associated with lower outstanding debt due to our chapter 11 bankruptcy. In addition, realized gains from derivative contracts were higher in the year ended December 31, 2020, which included the early termination of certain derivative contracts. During the year ended December 31, 2020, we terminated certain derivative contracts in advance of their natural expiration dates and received net proceeds of approximately $22.9 million during the period. These increases to operating cash flows in 2020 were partially offset by decreased oil and natural gas revenues as a result of lower realized commodity prices and lower production volumes than the comparable prior year period.

Investing Activities. Net cash flows used in investing activities for the year ended December 31, 2021 and 2020 were approximately $51.9 million and $72.4 million, respectively.

During the year ended December 31, 2021, we spent $52.6 million on oil and natural gas capital expenditures, of which $42.9 million related to drilling and completion costs and $6.8 million related to the development of our treating equipment and gathering support infrastructure. We received $0.9 million in proceeds from the sale of oil and natural gas properties.

During the year ended December 31, 2020, we spent $101.8 million on oil and natural gas capital expenditures, of which $65.1 million related to drilling and completion costs and $33.9 million related to the development of our treating equipment and gathering support infrastructure. We received $29.0 million in proceeds from the sale of oil and natural gas properties, primarily from the sale of the northern assets in our West Quito area in December 2020. In addition, we received $0.5 million in insurance proceeds associated with a casualty loss on our support infrastructure.

Financing Activities. Net cash flows provided by financing activities for the year ended December 31, 2021 and 2020 were approximately $27.4 million and $16.2 million, respectively.

During the year ended December 31, 2021, we borrowed $200.0 million under the Term Loan Agreement and paid in cash $14.2 million in debt issuance costs associated with the loan. A portion of the funds received from the Term Loan Agreement were used to refinance all amounts owed under the Senior Credit Agreement.

During the year ended December 31, 2020, net borrowings of $14.0 million under our Senior Credit Agreement were used to fund our drilling and completions program and the development of our treating equipment and gathering support facilities. We also borrowed $2.2 million under the PPP Loan to fund payroll costs, rent and utilities.

Term Loan Credit Facility

On November 24, 2021, we and our wholly owned subsidiary, Halcón Holdings, LLC (Borrower) entered into the Term Loan Agreement with Macquarie Bank Limited, as administrative agent, and certain other financial institutions party thereto, as lenders. The Term Loan Agreement amends and restates in its entirety our Senior Credit Agreement as discussed below. Pursuant to the Term Loan Agreement, the lenders have agreed to loan us (i) $200.0 million, which funded on November 24, 2021 and was partially used to refinance all amounts owed under the Senior Credit Agreement; (ii) up to $20.0 million, available to be drawn up to 18 months from November 24, 2021, subject to the satisfaction of certain conditions; and (iii) up to $15.0 million, which amount will be available to be drawn from the date certain wells included in the approved plan of development (APOD) are deemed producing APOD wells until up to 18 months after November 24, 2021, subject to the satisfaction of certain conditions. An additional $5.0 million is available for the issuance of letters of credit. The maturity date of the Term Loan Agreement is November 24, 2025. Until such maturity date, borrowings under the Term Loan Agreement shall bear interest at a rate per annum equal to LIBOR (or another applicable reference rate, as determined pursuant to the provisions of the Term Loan Agreement) plus an applicable margin of 7.00%.

We may be required to make mandatory prepayments of the loans under the Term Loan Agreement in connection with the incurrence of non-permitted debt, certain asset sales, and with excess cash on hand in excess of certain maximum levels. For each fiscal quarter after January 1, 2023, we shall make mandatory prepayments when the Consolidated Cash Balance, as defined in the Term Loan Agreement, exceeds $20.0 million. Until December 31, 2024, the forecasted APOD capital expenditures for the succeeding fiscal quarter are excluded for purposes of determining the Consolidated Cash Balance. We are required to make scheduled amortization payments in the aggregate amount of $120.0 million from the fiscal quarter ending March 31, 2023 through the fiscal quarter ending September 30, 2025. Amounts outstanding under the Term Loan Agreement are guaranteed by certain of the Borrower's direct and indirect subsidiaries and secured by a security interest in substantially all of the assets of the Borrower and such direct and indirect subsidiaries, and of the equity interests of the Borrower held by us. As part of the Term Loan Agreement there are certain restrictions on the transfer of assets, including cash, to Battalion from the guarantor subsidiaries.

The Term Loan Agreement also contains certain financial covenants, including the maintenance of (i) an Asset Coverage Ratio (as defined in the Term Loan Agreement) of not less than (A) 1.50 to 1.00 as of December 31, 2021 and March 31, 2022, (B) 1.60 to 1.00 as of June 30, 2022, (C) 1.70 to 1.00 as of September 30, 2022, and (D) 1.80 to 1.00 as of December 31, 2022 and each fiscal quarter thereafter, (ii) a Total Net Leverage Ratio (as defined in the Term Loan Agreement) of not greater than (A) 3.25 to 1.00 as of December 31, 2021 through and including June 30, 2022, (B) 3.00 to 1.00 as of September 30, 2022 and December 31, 2022, (C) 2.75 to 1.00 as of March 31, 2023, and (D) 2.50 to 1.00 as of each fiscal quarter thereafter, and (iii) a Current Ratio (as defined in the Term Loan Agreement) of not less than 1.00 to 1.00, each determined as of the last day of any fiscal quarter period. As of December 31, 2021, we were in compliance with the financial covenants under the Term Loan Agreement.

The Term Loan Agreement also contains an APOD for our Monument Draw acreage through the drilling and completion of certain wells. The Term Loan Agreement contains a proved developed producing production test and an APOD economic test which we must maintain compliance with otherwise, subject to any available remedies or waivers, we are required to immediately cease making expenditures in respect of the approved plan of development other than any expenditures deemed necessary by us in respect of no more than six additional approved plan of development wells.

The Term Loan Agreement also contains certain events of default, including non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy.

See Item 8. *Consolidated Financial Statements and Supplementary Data*–Note 6, *"Debt"* for additional information on the Term Loan Agreement.

Paycheck Protection Program Loan

On April 16, 2020, we entered into the PPP Loan for a principal amount of approximately $2.2 million from Bank of Montreal under the Paycheck Protection Program of the CARES Act, which is administered by the SBA. Pursuant to the terms of the CARES Act, the proceeds of the PPP Loan may be used for payroll costs, mortgage interest, rent or utility costs. The PPP Loan bears interest at a rate of 1.0% per annum and has a maturity date of April 16, 2022. As long as we made a timely application of forgiveness to the SBA, we were not required to make any payments under the PPP Loan until the forgiveness amount was communicated to us by the SBA. We applied for forgiveness of the amount due on the PPP Loan based on the use of the loan proceeds on eligible expenses in accordance with the terms of the CARES Act. Effective August 13, 2021, the principal amount of our PPP Loan was reduced to $0.2 million by the SBA and we recorded a gain on the extinguishment of the forgiven portion of the PPP Loan and related accrued interest of $2.1 million. The gain is presented in *"Gain (loss) on extinguishment of debt"* in the consolidated statements of operations for the year ended December 31, 2021.

The PPP Loan contains certain events of default including non-payment, breach of representations and warranties, cross-defaults to other loans with the lender or to material indebtedness, voluntary or involuntary bankruptcy, judgments and change in control.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States. We also describe the significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with our audit committee. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 1, "*Summary of Significant Events and Accounting Policies,"* for a discussion of additional accounting policies and estimates made by management.

Oil and Natural Gas Activities

Accounting for oil and natural gas activities is subject to unique rules. Two generally accepted methods of accounting for oil and natural gas activities are available-successful efforts and full cost. The most significant differences between these two methods are the treatment of unsuccessful exploration costs and the manner in which the carrying value of oil and natural gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed as they are incurred upon a determination that the well is uneconomical while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and natural gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and natural gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using the unweighted arithmetic average of the first day of the month for each of the 12-month prices for oil and natural gas within the period, holding prices and costs constant and applying a 10% discount rate.

Full Cost Method

We use the full cost method of accounting for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized into a cost center (the amortization base or full cost pool). Such amounts include the cost of drilling and equipping productive wells, treating equipment and gathering support facilities costs, dry hole costs, lease acquisition costs and delay rentals. All general and administrative costs unrelated to drilling activities are expensed as incurred. The capitalized costs of our evaluated oil and natural gas properties, plus an estimate of our future development and abandonment costs are amortized on a unit-of-production method based on our estimate of total proved reserves. Our financial position and results of operations could have been significantly different had we used the successful efforts method of accounting for our oil and natural gas activities.

Proved Oil and Natural Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States and SEC guidelines. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depletion, depreciation and accretion expense and the full cost ceiling test limitation. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under defined economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The accuracy of a reserve estimate is a function of (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions; and (iv) the judgment of the persons preparing the estimate. The data for a given reservoir may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and natural gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

Our estimated proved reserves for the years ended December 31, 2021, 2020 and 2019 were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. *Consolidated Financial Statements and Supplementary Data—"Supplemental Oil and Gas Information (Unaudited)*."

Depletion Expense

Our rate of recording depletion expense is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record depletion expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. At December 31, 2021, a five percent positive revision to proved reserves would decrease the depletion rate by approximately $0.37 per Boe and a five percent negative revision to proved reserves would increase the depletion rate by approximately $0.40 per Boe.

Full Cost Ceiling Test Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and could result in lower amortization expense in future periods. The present value of our estimated proved reserves (discounted at 10%) is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of our oil and natural gas properties could occur in the future.

If the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ended December 31, 2021 had been 10% lower while all other factors remained constant, our ceiling amount related to our net book value of oil and natural gas properties would have been reduced by approximately $182.9 million and would not have generated a full cost ceiling impairment.

Future Development Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production facilities, gathering systems and related structures and restoration costs. We develop estimates of these costs for each of our properties based upon their geographic location, type of production facility, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. At December 31, 2021, a five percent increase in future development and abandonment costs would increase the depletion rate by approximately $0.27 per Boe and a five percent decrease in future development and abandonment costs would decrease the depletion rate by $0.27 per Boe.

Accounting for Derivative Instruments and Hedging Activities

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging* (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, in accordance with our policy, we may hedge a portion of our forecasted oil and natural gas production. We elected to not designate any of our positions for hedge accounting. Accordingly, we record the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

Income Taxes

Our provision for taxes includes both state and federal taxes. We account for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. We classify all deferred tax assets and liabilities, along with any related valuation allowance, as noncurrent on the consolidated balance sheets.

In assessing the need for a valuation allowance on our deferred tax assets, we consider possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies. We consider all available evidence (both positive and negative) in determining whether a valuation allowance is required. Based upon the evaluation of available evidence we recorded a decrease of $57.8 million to our valuation allowance as a result of increases to deferred tax assets for deferred deductions and net operating losses offset by the write-off of deferred tax assets for oil and gas properties and other deferred tax assets during 2021. A valuation allowance of $431.7 million has been applied against our deferred tax assets as of December 31, 2021.

We follow ASC 740, *Income Taxes* (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the financial statements. We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows. The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

Comparison of Results of Operations

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

We reported a net loss of $28.3 million and $229.7 million for the year ended December 31, 2021 and 2020, respectively. The table included below sets forth financial information for the periods presented.

In thousands (except per unit and per Boe amounts)	Years Ended December 31, 2021	Years Ended December 31, 2020	Change
Net income (loss)	$ (28,317)	$ (229,707)	$ 201,390
Operating revenues:			
Oil	213,512	125,985	87,527
Natural gas	35,248	5,818	29,430
Natural gas liquids	35,394	14,972	20,422
Other	1,051	1,514	(463)
Operating expenses:			
Production:			
Lease operating	43,977	42,106	1,871
Workover and other	3,224	3,709	(485)
Taxes other than income	12,312	10,056	2,256
Gathering and other	60,396	56,016	4,380
Restructuring	—	2,580	(2,580)
General and administrative:			
General and administrative	14,504	15,878	(1,374)
Stock-based compensation	2,010	2,578	(568)
Depletion, depreciation and accretion:			
Depletion – Full cost	44,613	60,543	(15,930)
Depreciation – Other	318	925	(607)
Accretion expense	477	585	(108)
Full cost ceiling impairment	—	215,145	(215,145)
Other income (expenses):			
Net gain (loss) on derivative contracts	(125,619)	38,759	(164,378)
Interest expense and other	(8,018)	(6,634)	(1,384)
Gain (loss) on extinguishment of debt	1,946	—	1,946
Production:			
Crude oil – MBbls	3,196	3,446	(250)
Natural gas – MMcf	9,447	8,769	678
Natural gas liquids – MBbls	1,157	1,262	(105)
Total MBoe[(1)]	5,928	6,170	(242)
Average daily production – Boe[(1)]	16,241	16,858	(617)
Average price per unit [(2)]:			
Crude oil price - Bbl	$ 66.81	$ 36.56	$ 30.25
Natural gas price - Mcf	3.73	0.66	3.07
Natural gas liquids price - Bbl	30.59	11.86	18.73
Total per Boe[(1)]	47.93	23.79	24.14
Average cost per Boe:			
Production:			
Lease operating	$ 7.42	$ 6.82	$ 0.60
Workover and other	0.54	0.60	(0.06)
Taxes other than income	2.08	1.63	0.45
Gathering and other	10.19	9.08	1.11
Restructuring	—	0.42	(0.42)
General and administrative:			
General and administrative	2.45	2.57	(0.12)
Stock-based compensation	0.34	0.42	(0.08)
Depletion	7.53	9.81	(2.28)

(1) *Determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on approximate energy equivalency. This is an energy content correlation and does not reflect the value or price relationship between the commodities.*

(2) *Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.*

Oil, natural gas and natural gas liquids revenues were $284.2 million and $146.8 million for the year ended December 31, 2021 and 2020, respectively. The increase in revenue is primarily attributable to an approximate $24.14 per Boe increase in our average realized prices (excluding the effects of hedging arrangements). The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, transportation take-away capacity constraints, inventory storage levels, quality of production, basis differentials and other factors. For the year ended December 31, 2021 and 2020, production averaged 16,241 Boe/d and 16,858 Boe/d, respectively. Average daily oil and natural gas production was impacted by the temporary shut-in of production amounting to approximately 300 Boe/d and 1,300 Boe/d in 2021 and 2020, respectively. In February 2021, we temporarily shut-in production due to inclement weather. In May and June 2020, we temporarily shut-in production in response to historically low commodity prices. Current year production was also impacted by third-party processing curtailments and downtime resulting from facility upgrades and repairs.

Lease operating expenses were $44.0 million and $42.1 million for the year ended December 31, 2021 and 2020, respectively. On a per unit basis, lease operating expenses were $7.42 per Boe and $6.82 per Boe for the year ended December 31, 2021 and 2020, respectively. The increase in lease operating expenses in 2021 results from a market increase associated with maintenance, power and chemical costs partially offset by decreased salt water disposal costs due to lower production volumes and less produced water.

Workover and other expenses were $3.2 million and $3.7 million for the year ended December 31, 2021 and 2020, respectively. On a per unit basis, workover and other expenses were $0.54 per Boe and $0.60 per Boe for the year ended December 31, 2021 and 2020, respectively. The decreased workover and other expenses in 2021 relate to preventative operational measures previously undertaken to mitigate potential future failures in producing wells.

Taxes other than income were $12.3 million and $10.1 million for the year ended December 31, 2021 and 2020, respectively. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease. On a per unit basis, taxes other than income were $2.08 per Boe and $1.63 per Boe for the year ended December 31, 2021 and 2020, respectively.

Gathering and other expenses were $60.4 million and $56.0 million for the year ended December 31, 2021 and 2020, respectively. Gathering and other expenses include gathering fees paid to third parties on our oil and natural gas production and operating expenses of our gathering support infrastructure. Approximately $22.7 million and $13.9 million for the year ended December 31, 2021 and 2020, respectively, relate to gathering and marketing fees paid to third parties on our oil and natural gas production. Gathering and marketing fees increased in 2021 as we marketed higher quantities of sour gas production to third parties in the current year period. Approximately $37.7 million and $38.7 million for the year ended December 31, 2021 and 2020, respectively, relate to operating expenses on our treating equipment and gathering support facilities. The decrease in treating equipment and gathering support facilities expenses in 2021 results from lower operating expenses associated with our treating equipment, as fewer sour gas production volumes were processed through our hydrogen sulfide treating plant in the current year period, which were partially offset by higher electricity and buy back fuel costs incurred as a result of inclement weather in February 2021 and higher chemical costs to improve the quality of treated oil. Also included are $3.4 million of rig stacking charges for the year ended December 31, 2020.

Restructuring expense was approximately $2.6 million for the year ended December 31, 2020. During the year ended December 31, 2020, we incurred restructuring charges related to the consolidation into one corporate office and had reductions in our workforce due to efforts to improve efficiencies and go forward costs. In May 2020, in furtherance of the consolidation into one corporate office, we exercised a one-time early termination option under the lease agreement for our office space in Denver, Colorado.

General and administrative expense was $14.5 million and $15.9 million for the year ended December 31, 2021 and 2020, respectively. The decrease in general and administrative expense in the current year period is associated with a decrease in professional fees and information technology expenses, as well as the Employee Retention Credit. This decrease is partially offset by lower 2020 payroll costs, as the 2020 period included a $1.6 million reduction to general and administrative expenses related to our change in estimate of discretionary cash incentives. In late March 2020, due to changes in market conditions and decreased commodity prices, we determined that previously accrued discretionary cash incentives related to 2019 would not be paid, causing a $1.6 million reduction to general and administrative expenses in the 2020 period. On a per unit basis, general and administrative expense were $2.45 per Boe and $2.57 per Boe for the year ended December 31, 2021 and 2020, respectively.

Stock-based compensation expense was $2.0 million and $2.6 million for the year ended December 31, 2021 and 2020, respectively. Stock-based compensation expense decreased in the current year due to restricted stock units vesting during the first quarter of 2021.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production for the current period to total reserve volumes of evaluated properties as of the beginning of the period. Depletion expense was $44.6 million and $60.5 million for the year ended December 31, 2021 and 2020, respectively. On a per unit basis, depletion expense was $7.53 per Boe and $9.81 per Boe for the year ended December 31, 2021 and 2020, respectively. The depletable base of our unit of production calculation was reduced by the full cost ceiling test impairments incurred in 2020 and increased by future development costs associated with PUD reserve additions. We also experienced an increase in proved reserve volumes, primarily from PUD reserve additions, which resulted in a decrease to our depletion rate in 2021 as compared to 2020.

Under the full cost method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling”, based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. During 2020, the net book value of our oil and gas properties at June 30, September 30 and December 31 exceeded the ceiling amount and we recorded full cost ceiling test impairments before income taxes of $60.1 million, $128.3 million and $26.7 million, respectively, for the periods. The ceiling test impairments during 2020 were primarily driven by decreases in the first-day-of-the-month 12-month average prices for crude oil used in the ceiling test calculation. Additionally, during the three months ended September 30, 2020, the transfer of $23.6 million of unevaluated property costs to the full cost pool due to our intent to focus available capital on Monument Draw also contributed to the impairment recorded for the period. During the three months ended December 31, 2020, proved undeveloped reserves additions as a result of changes to our five year development plan partially offset the impact of the average price decline on the impairment for the period.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. At December 31, 2021, we had a $3.9 million derivative asset, $1.4 million of which was classified as current, and we had a $65.5 million derivative liability, $58.3 million of which was classified as current. We recorded a net derivative loss of $125.6 million ($47.7 million net unrealized loss and $77.9 million net realized loss on settled contracts) for the year ended December 31, 2021. We recorded a net derivative gain of $38.8 million ($6.1 million net unrealized loss and $44.9 million net realized gain on settled and early terminated contracts) for the year ended December 31, 2020. During 2020, we terminated certain derivative contracts in advance of their natural expiration dates and received net proceeds of approximately $22.9 million, which were included in the $44.9 million net realized gains for the year.

Interest expense and other was $8.0 million and $6.6 million for the year ended December 31, 2021 and 2020, respectively. Interest expense and other increased in the current period due to interest and the amortization of debt issuance costs associated with our Term Loan Agreement.

During the year ended December 31, 2021, we recorded a gain on the extinguishment of the forgiven portion of the PPP Loan and related accrued interest of $2.1 million. We applied for forgiveness of the amount due on the PPP Loan based on the use of the loan proceeds on eligible expenses in accordance with the terms of the CARES Act. Effective August 13, 2021, the principal amount of our PPP Loan was reduced from $2.2 million to $0.2 million by the SBA. This gain was partially offset by a $0.1 million extinguishment loss resulting from the refinancing of our Senior Credit Agreement.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 1, "*Summary of Significant Events and Accounting Policies*."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivative Instruments and Hedging Activity

We are exposed to various risks, including energy commodity price risk, such as price differentials between the NYMEX commodity price and the index price at the location where our production is sold. When oil and natural gas prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include fixed-price swaps, costless collars, basis swaps and WTI NYMEX rolls. The total volumes that we hedge through the use of our derivative instruments varies from period to period, however, our requirement under our Term Loan Agreement, is to hedge approximately 50% to 85% of our anticipated oil and natural gas production, in varying percentages by year, on a rolling basis for the next four years, when derivative contracts are available at terms and prices acceptable to us. Our hedge policies and objectives may change significantly as our operational profile and contractual obligations change but remain consistent with the requirements in effect under our Term Loan Agreement. We do not enter into derivative contracts for speculative trading purposes.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. It is our policy to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competitive market makers. As of December 31, 2021, we did not post collateral under any of our derivative contracts as they are secured under our Term Loan Agreement.

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging*, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 8, *"Derivative and Hedging Activities,"* for more details.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, *Financial Instruments*, (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, restricted cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 7, "*Fair Value Measurements,"* for additional information.

Interest Rate Sensitivity

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

At December 31, 2021, the principal amount of our debt was $200.1 million, of which less than 0.1% bears interest at a weighted average fixed interest rate of 1.0% per year. The remaining 99.9% of our total debt at December 31, 2021 bears interest at floating and variable interest rates that are tied to LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. At December 31, 2021, the weighted average interest rate on our variable rate debt was 7.22% per year. If the balance of our variable interest rate at December 31, 2021 were to remain constant, a 10% change in market interest rates would impact our cash flows by approximately $1.4 million per year.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Battalion Oil Corporation (the Company), including the Company's Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company's internal control system was designed to provide reasonable assurance to the Company's Management and Board of Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on this evaluation, Management concluded that Battalion Oil Corporation's internal control over financial reporting was effective as of December 31, 2021.

This Annual Report on Form 10-K does not include an attestation report of the Company's independent registered public accounting firm regarding the effectiveness of the Company's internal control over financial reporting. Management's report was not subject to attestation by its independent registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit smaller reporting companies to provide only Management's report in this Annual Report on Form 10-K.

/s/ RICHARD H. LITTLE
Richard H. Little
Chief Executive Officer

/s/ R. KEVIN ANDREWS
R. Kevin Andrews
Executive Vice President,
Chief Financial Officer and Treasurer

Houston, Texas
March 7, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Battalion Oil Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Battalion Oil Corporation and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of operations, stockholders' equity, and cash flows, for the years ended December 31, 2021 and 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the years ended December 31, 2021 and 2020, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved especially challenging, subjective, or complex judgements. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which they relate.

Proved Oil and Natural Gas Property and Depletion — Oil and Natural Gas Reserve Quantities — Refer to Note 1 and 5 to the financial statements

Critical Audit Matter Description

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. The Company's proved oil and natural gas properties are depleted using the units of production method and are evaluated for impairment by the full cost ceiling impairment test utilizing the Company's oil and natural gas reserves in accordance with accounting principles generally accepted in the United States and SEC guidelines. The development of the Company's oil and natural gas reserve quantities and the related net present value of future cash flows from the related proved reserves requires management to make significant estimates and assumptions related to the intent and ability to complete undeveloped proved reserves within a five-year development period, as prescribed by SEC guidelines, and the future development costs associated with these reserves. The Company engages an independent reservoir engineering firm, management's specialist, to estimate oil and natural gas quantities using these estimates and assumptions and engineering data. Changes in these assumptions or engineering data could have a significant impact on the amount of depletion and impairment recorded for the Company's proved oil and natural gas properties. The gross proved oil and natural gas properties balance was $569.9 million with an accumulated depletion balance of $339.8 million as of December 31, 2021. Depletion expense was $44.6 million for the year ended December 31, 2021.

Given the significant judgments made by management and management's specialist, performing audit procedures to evaluate the Company's oil and natural gas reserve quantities and the related net cash flows, including management's estimates and assumptions related to the intent and ability to complete undeveloped proved reserves within the five-year development period and future development costs, requires a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures of management's significant judgments and assumptions related to oil and natural gas reserves quantities and estimates of the future net cash flows included the following, among others:

- We evaluated the reasonableness of management's five-year development plan by comparing the forecasts to:
  - Historical conversions of proved undeveloped oil and natural gas reserves into proved developed oil and natural gas reserves.
  - Internal communications to management and the Board of Directors.
  - Forecasted information included in Company press releases as well as in analyst and industry reports for the Company and certain of its peer companies.
  - The financial capability of the Company to execute its drilling program.
- We evaluated the reasonableness of management's estimate of future development costs by comparing the estimate to:
  - Historical development of similar wells, including location of the well.
  - Future development costs to internal data.
  - Internal communications to management and the Board of Directors.
  - Approval for expenditures.

- We evaluated the reasonableness of management's estimated reserve quantities by performing the following:
  - Evaluating the experience, qualifications and objectivity of management's specialist, an independent reservoir engineering firm.
  - Performing analytical procedures on the reserve quantities developed by management's specialist.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 7, 2022

We have served as the Company's auditor since 2012.

BATTALION OIL CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended December 31, 2021	2020
Operating revenues:		
Oil, natural gas and natural gas liquids sales:		
Oil	$ 213,512	$ 125,985
Natural gas	35,248	5,818
Natural gas liquids	35,394	14,972
Total oil, natural gas and natural gas liquids sales	284,154	146,775
Other	1,051	1,514
Total operating revenues	285,205	148,289
Operating expenses:		
Production:		
Lease operating	43,977	42,106
Workover and other	3,224	3,709
Taxes other than income	12,312	10,056
Gathering and other	60,396	56,016
Restructuring	—	2,580
General and administrative	16,514	18,456
Depletion, depreciation and accretion	45,408	62,053
Full cost ceiling impairment	—	215,145
Total operating expenses	181,831	410,121
Income (loss) from operations	103,374	(261,832)
Other income (expenses):		
Net gain (loss) on derivative contracts	(125,619)	38,759
Interest expense and other	(8,018)	(6,634)
Gain (loss) on extinguishment of debt	1,946	—
Total other income (expenses)	(131,691)	32,125
Income (loss) before income taxes	(28,317)	(229,707)
Income tax benefit (provision)	—	—
Net income (loss)	$ (28,317)	$ (229,707)
Net income (loss) per share of common stock:		
Basic	$ (1.74)	$ (14.18)
Diluted	$ (1.74)	$ (14.18)
Weighted average common shares outstanding:		
Basic	16,261	16,204
Diluted	16,261	16,204

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

BATTALION OIL CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	December 31, 2021	December 31, 2020
Current assets:		
Cash and cash equivalents	$ 46,864	$ 4,295
Accounts receivable, net	36,806	32,242
Assets from derivative contracts	1,383	8,559
Restricted cash	1,495	—
Prepaids and other	1,366	2,740
Total current assets	87,914	47,836
Oil and natural gas properties (full cost method):		
Evaluated	569,886	509,274
Unevaluated	64,305	75,494
Gross oil and natural gas properties	634,191	584,768
Less - accumulated depletion	(339,776)	(295,163)
Net oil and natural gas properties	294,415	289,605
Other operating property and equipment:		
Other operating property and equipment	3,467	3,535
Less - accumulated depreciation	(1,035)	(1,149)
Net other operating property and equipment	2,432	2,386
Other noncurrent assets:		
Assets from derivative contracts	2,515	4,009
Operating lease right of use assets	721	310
Funds in escrow and other	2,270	2,351
Total assets	$ 390,267	$ 346,497
Current liabilities:		
Accounts payable and accrued liabilities	$ 62,826	$ 58,928
Liabilities from derivative contracts	58,322	22,125
Current portion of long-term debt	85	1,720
Operating lease liabilities	369	403
Total current liabilities	121,602	83,176
Long-term debt, net	181,565	158,489
Other noncurrent liabilities:		
Liabilities from derivative contracts	7,144	4,291
Asset retirement obligations	11,896	10,583
Operating lease liabilities	352	—
Other	4,003	—
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Common stock: 100,000,000 shares of $0.0001 par value authorized; 16,273,913 and 16,203,979 shares issued and outstanding as of December 31, 2021 and 2020, respectively	2	2
Additional paid-in capital	332,187	330,123
Retained earnings (accumulated deficit)	(268,484)	(240,167)
Total stockholders' equity	63,705	89,958
Total liabilities and stockholders' equity	$ 390,267	$ 346,497

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

BATTALION OIL CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands)

	Common Stock		Additional Paid-In	Retained Earnings (Accumulated	Stockholders'
	Shares	Amount	Capital	Deficit)	Equity
Balances at December 31, 2019	16,204	$ 2	$ 327,108	$ (10,460)	$ 316,650
Net income (loss)	—	—	—	(229,707)	(229,707)
Equity issuance costs and other	—	—	(14)	—	(14)
Stock-based compensation	—	—	3,029	—	3,029
Balances at December 31, 2020	16,204	2	330,123	(240,167)	89,958
Net income (loss)	—	—	—	(28,317)	(28,317)
Long-term incentive plan vestings	96	—	—	—	—
Reduction in shares to cover individuals' tax withholding	(26)	—	(290)	—	(290)
Stock-based compensation	—	—	2,354	—	2,354
Balances at December 31, 2021	16,274	$ 2	$ 332,187	$ (268,484)	$ 63,705

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

BATTALION OIL CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,	
	2021	2020
Cash flows from operating activities:		
Net income (loss)	$ (28,317)	$ (229,707)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depletion, depreciation and accretion	45,408	62,053
Full cost ceiling impairment	—	215,145
Stock-based compensation, net	2,010	2,578
Unrealized loss (gain) on derivative contracts	47,721	6,143
Amortization of debt issuance costs	379	—
Reorganization items, net	—	(6,565)
Loss (gain) on extinguishment of debt	(1,946)	—
Accrued settlements on derivative contracts	7,030	170
Other expense (income)	(567)	142
Change in assets and liabilities:		
Accounts receivable	(4,647)	13,513
Prepaids and other	636	4,712
Accounts payable and accrued liabilities	865	(17,987)
Net cash provided by (used in) operating activities	68,572	50,197
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(52,557)	(101,788)
Proceeds received from sales of oil and natural gas assets	947	29,029
Acquisition of oil and natural gas properties	—	(23)
Other operating property and equipment capital expenditures	(371)	(82)
Funds held in escrow and other	68	510
Net cash provided by (used in) investing activities	(51,913)	(72,354)
Cash flows from financing activities:		
Proceeds from borrowings	374,000	148,209
Repayments of borrowings	(332,085)	(132,000)
Debt issuance costs	(14,220)	—
Equity issuance costs and other	(290)	(32)
Net cash provided by (used in) financing activities	27,405	16,177
Net increase (decrease) in cash, cash equivalents and restricted cash	44,064	(5,980)
Cash, cash equivalents and restricted cash at beginning of period	4,295	10,275
Cash, cash equivalents and restricted cash at end of period	$ 48,359	$ 4,295
Supplemental cash flow information:		
Cash paid (received) for interest	$ 8,485	$ 7,577
Cash paid (refunded) for income taxes	—	(1,250)
Cash paid for reorganization items	—	6,565
Disclosure of non-cash investing and financing activities:		
Asset retirement obligations	$ 836	$ (592)
Accrued equity issuance costs	—	(19)
Accrued debt issuance costs	379	—

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

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

Battalion Oil Corporation (Battalion or the Company) is the successor reporting company to Halcón Resources Corporation (Halcón). On January 21, 2020, Battalion filed a Certificate of Amendment to the Company's Amended and Restated Certificate of Incorporation with the Delaware Secretary of State to effect a change of the Company's corporate name from Halcón Resources Corporation to Battalion Oil Corporation.

Battalion is an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. The Company operates in one segment which focuses on oil and natural gas acquisition, production, exploration and development. Allocation of capital is made across the Company's entire portfolio without regard to operating area. All intercompany accounts and transactions have been eliminated. The Company has evaluated events and transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.

Risk and Uncertainties

The Company is continuously monitoring the current and potential impacts of the novel coronavirus (COVID-19) pandemic on its business, including how it has and may continue to impact its operations, financial results, liquidity, contractors, customers, employees and vendors, and taking appropriate actions in response, including implementing various measures to ensure the continued operation of its business in a safe and secure manner. In 2020, COVID-19 and governmental actions to contain the pandemic contributed to an economic downturn, reduced demand for oil and natural gas and, together with a price war involving the Organization of Petroleum Exporting Countries (OPEC)/Saudi Arabia and Russia, depressed oil and natural gas prices to historically low levels. Although OPEC and Russia subsequently agreed to reduce production, downward pressure on prices continued for several months, particularly given concerns over the impacts of the economic downturn on demand. As a consequence, beginning in March 2020, the Company realized lower revenue as a result of commodity price declines, resulting in the Company temporarily shutting in producing wells in May and June 2020, which further contributed to lower revenues that year. Additionally in 2020, as discussed further in Note 5, *"Oil and Natural Gas Properties,"* the Company incurred ceiling test impairments, which were primarily driven by a decline in the average pricing required to be used in the valuation of the Company's reserves for ceiling test purposes.

During 2021, widespread availability of COVID-19 vaccines in the United States and elsewhere combined with accommodative governmental monetary and fiscal policies and other factors, led to a rebound in demand for oil and natural gas and increases in oil and natural gas prices. Further, at present, OPEC and Russia have been coordinating production increases to maintain supply and demand balance, stabilize prices and avoid market disruptions. However, there remains the potential for such cooperation to fail and for demand for oil and natural gas to be adversely impacted by the economic effects of the ongoing COVID-19 pandemic, including as a consequence of the circulation of more infectious "variants" of the disease, vaccine hesitancy, waning vaccine effectiveness or other factors. As a consequence, the Company is unable to predict whether oil and natural gas prices will remain at current levels or will be adversely impacted by the same sorts of factors that negatively impacted prices during 2020. Furthermore, the health of the Company's employees, contractors and vendors, and its ability to meet staffing needs in its operations and critical functions remain concerns and cannot be predicted, nor can the impact on the Company's customers, vendors and contractors. Any material effect on these parties could adversely impact the Company. These and other factors could affect the Company's operations, earnings and cash flows and could cause its results to not be comparable to those of the same period in previous years. The results presented in this Form 10-K are not necessarily indicative of future operating results. For further information regarding the actual and potential impacts of COVID-19 on the Company, see *"Risk Factors"* in Item 1A of this Annual Report on Form 10-K.

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Use of Estimates

The preparation of the Company's consolidated financial statements in conformity with accounting principles generally accepted in the United States requires the Company's management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Estimates and assumptions that, in the opinion of management of the Company, are significant include oil and natural gas revenue accruals, capital and operating expense accruals, oil and natural gas reserves, depletion relating to oil and natural gas properties, asset retirement obligations, and fair value estimates. The Company bases its estimates and judgments on historical experience and on various other assumptions and information believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be predicted with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company's operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company's consolidated financial statements.

Cash, Cash Equivalents and Restricted Cash

The Company considers all highly liquid short-term investments with a maturity of three months or less at the time of purchase to be cash equivalents. These investments are carried at cost, which approximates fair value. Amounts in the consolidated balance sheets included in "*Cash and cash equivalents*" and "*Restricted cash*" reconcile to the Company's consolidated statements of cash flows as follows:

	December 31, 2021	December 31, 2020
Cash and cash equivalents	$ 46,864	$ 4,295
Restricted cash	1,495	—
Total cash, cash equivalents and restricted cash	$ 48,359	$ 4,295

Restricted cash consists primarily of funds to collateralize letters of credit outstanding.

Accounts Receivable and Allowance for Doubtful Accounts

The Company's accounts receivable are primarily receivables from joint interest owners and oil and natural gas purchasers. Accounts receivable are recorded at the amount due, less an allowance for doubtful accounts, when applicable. The Company establishes provisions for losses on accounts receivable if it determines that collection of all or part of the outstanding balance is doubtful. The Company regularly reviews collectability and establishes or adjusts the allowance for doubtful accounts as necessary using the specific identification method. As of December 31, 2021 and 2020 allowances for doubtful accounts were approximately $0.2 million for both periods.

Oil and Natural Gas Properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration and development of proved and unproved oil and natural gas properties, including the costs of abandoned properties, treating equipment and gathering support facilities, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to estimated proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on estimated proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company reviews its unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization. Investments in unevaluated oil and natural gas properties and exploration and development projects for which depletion expense is not currently recognized, and for which exploration or development activities are in progress, qualify for interest capitalization. The Company determines capitalized interest, when applicable, by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred that were excluded from the full cost pool; however, the amount of capitalized interest cannot exceed the amount of gross interest expense incurred in any given period. The Company's accounting policy on the capitalization of interest establishes thresholds for the determination of a development project for the purpose of interest capitalization.

Other Operating Property and Equipment

Other operating property and equipment are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: buildings, twenty years; automobiles and computers, three years; computer software, fixtures, furniture and equipment, five years; trailers, seven years; heavy equipment, eight to ten years and leasehold improvements, lease term. Land and artwork are not depreciated. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures which increase the life or productive capacity of an asset are capitalized and depreciated over the estimated remaining useful life of the asset.

The Company reviews its other operating property and equipment for impairment in accordance with ASC 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate other operating property and equipment for impairment as events occur or circumstances change that would more likely than not reduce the fair value below the carrying amount. If the carrying amount is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of its other operating property and equipment at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Concentrations of Credit Risk

The Company's primary concentrations of credit risk are the risks of uncollectible accounts receivable and of nonperformance by counterparties under the Company's derivative contracts. Each reporting period, the Company assesses the recoverability of material receivables using historical data, current market conditions and reasonable and supportable forecasts of future economic conditions to determine expected collectability of its material receivables.

The Company's accounts receivable are primarily receivables from joint interest owners and oil and natural gas purchasers. The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, the Company has not experienced any significant losses from uncollectible accounts from its oil and natural gas purchasers. In 2021, three individual purchasers of the Company's production, Western Refining, Inc., Sunoco Inc. and Salt Creek Midstream, LLC, each accounted for more than 10% of total sales, collectively representing 73% of its total sales for the year. In 2020, two individual purchasers of the Company's production, Western Refining Inc. and Sunoco Inc., each accounted for more than 10% of total sales, collectively representing 57% of its total sales for the year.

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The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payments for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners consist primarily of independent oil and natural gas producers. Joint operating agreements govern the operations of an oil or natural gas well and, in most instances, provide for offsetting of amounts payable or receivable between the Company and its joint interest owners. If the oil and natural gas exploration and production industry in general was adversely affected, the ability of the Company's joint interest partners to reimburse the Company could be adversely affected.

The Company's exposure to credit risk under its derivative contracts is varied among major financial institutions with investment grade credit ratings, where it has master netting agreements which provide for offsetting of amounts payable or receivable between the Company and the counterparty. To manage counterparty risk associated with derivative contracts, the Company selects and monitors counterparties based on an assessment of their financial strength and/or credit ratings. At December 31, 2021, the Company's derivative counterparties include two major financial institutions, both of which are secured lenders under the Term Loan Agreement.

Employee Retention Credit

The Coronavirus Aid, Relief and Economic Security Act (the CARES Act) was enacted on March 27, 2020 and included, among other things, provisions relating to refundable payroll tax credits (the Employee Retention Credit or ERC). As provided for in the CARES Act and subsequent legislation which modified and extended the provisions included therein, the ERC allows for a refundable tax credit against certain employment taxes equal to 50% of the first $10,000 in qualified wages paid to each employee after March 12, 2020 and through December 31, 2020 and 70% of the first $10,000 in qualified wages paid to each employee, per calendar quarter, after December 31, 2020 through September 30, 2021. During the year ended December 31, 2021, the Company determined that the qualifications for the Employee Retention Credit were met and filed the corresponding applications for the applicable 2020 and 2021 periods. The Company recognized an approximate $0.7 million Employee Retention Credit during the year ended December 31, 2021, with approximately $0.5 million recorded to *"General and administrative"* and approximately $0.2 million recorded to *"Lease operating"* in the consolidated statements of operations.

Risk Management Activities

The Company follows ASC 815, *Derivatives and Hedging* (ASC 815). From time to time, in accordance with the Company's policy, it may hedge a portion of its forecasted oil and natural gas production. The Company recognized all derivative instruments as either assets or liabilities in the consolidated balance sheets at fair value. The Company has elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

Income Taxes

The Company accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company classifies all deferred tax assets and liabilities, along with any related valuation allowance, as noncurrent on the consolidated balance sheets.

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The Company follows ASC 740, *Income Taxes* (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the consolidated financial statements.

The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the consolidated financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

The Company has no liability for unrecognized tax benefits as of December 31, 2021 and 2020. Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the consolidated statements of operations or consolidated balance sheets as of December 31, 2021 and 2020. In addition, the Company does not believe that there are any positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease within the next twelve months.

The Company includes interest and penalties relating to uncertain tax positions within *"Interest expense and other"* on the Company's consolidated statements of operations. Refer to Note 12, *"Income Taxes,"* for more details.

Generally, the Company's income tax years 2018 through 2021 remain open for federal purposes and are subject to examination by federal tax authorities. The Company's income tax returns are also subject to audit by the tax authorities in Louisiana, Mississippi, North Dakota, Oklahoma, Texas, Pennsylvania, Ohio and certain other state taxing jurisdictions where the Company has, or previously had, operations. In certain jurisdictions the Company operates through more than one legal entity, each of which may have different open years subject to examination. The open years for state purposes can vary from the normal three year statue expiration period for federal purposes.

Tax audits may be ongoing at any point in time. Tax liabilities are recorded based on estimates of additional taxes which may be due upon the conclusion of these audits. Estimates of these tax liabilities are made based upon prior experience and are updated for changes in facts and circumstances. However, due to the uncertain and complex application of tax regulations, it is possible that the ultimate resolution of audits may result in liabilities which could be materially different from these estimates.

Asset Retirement Obligations

ASC 410, *Asset Retirement and Environmental Obligations* (ASC 410) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records asset retirement obligations to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells, treating equipment and gathering support facilities. The Company estimates the expected cash flows associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should these indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells, treating equipment and gathering support facilities as these obligations are incurred.

401(k) Plan

The Company sponsors a 401(k) tax deferred savings plan, whereby the Company matches a portion of employees' contributions in cash. Participation in the plan is voluntary and all employees of the Company who are 18 years of age are eligible to participate. The Company provided matching contributions of $0.8 million for each of the years ended December 31, 2021 and 2020. The Company matches employee contributions dollar-for-dollar on the first 10% of an employee's pre-tax earnings, subject to individual IRS limitations.

Restructuring

During 2020, the Company incurred approximately $2.6 million in restructuring charges related to the consolidation into one corporate office and reductions in its workforce due to efforts to improve efficiencies and reduce future costs. In May 2020, in furtherance of the consolidation into one corporate office, the Company exercised a one-time early termination option under the lease agreement for the Company's office space in Denver, Colorado. These costs were recorded in *"Restructuring"* on the consolidated statements of operations. Refer to Note 2, *"Leases,"* for further details.

Change in Estimate

In late March 2020, due to changes in market conditions and decreased commodity prices, the Company determined that previously accrued discretionary cash incentives related to 2019 would not be paid, causing a $1.6 million reduction to *"General and administrative"* on the condensed consolidated statement of operations for the year ended December 31, 2020.

Recently Issued Accounting Pronouncements

In March 2020, the FASB issued Accounting Standards Update (ASU) No. 2020-04, *Reference Rate Reform (Topic 848)* (ASU 2020-04), in response to the risk of cessation of the London Interbank Offered Rate (LIBOR). This amendment provides optional expedients and exceptions for applying generally accepted accounting principles to contracts, hedging arrangements, and other transactions that reference LIBOR. ASU 2020-04 will be in effect through December 31, 2022. The Company is currently evaluating ASU 2020-04 and the impact it may have on its operating results, financial position and disclosures.

In December 2019, the FASB issued ASU No. 2019-12, *Income Taxes (Topic 740) – Simplifying the Accounting for Income Taxes* (ASU 2019-12) as part of their simplification initiative. ASU 2019-12 simplifies the accounting for income taxes by removing certain exceptions and by clarifying and amending existing guidance. ASU 2019-12 is effective for interim and annual periods beginning after December 15, 2020 with early adoption permitted. The Company adopted ASU 2019-12 effective January 1, 2021. The adoption of ASU 2019-12 did not have a material impact on the Company's operating results, financial position or disclosures.

2. LEASES

The Company determines if an arrangement is a lease at contract inception. A lease exists when a contract conveys to the customer the right to control the use of an identified asset for a period of time in exchange for consideration. The definition of a lease embodies two conditions: (1) there is an identified asset in the contract that is land or a depreciable asset, and (2) the customer has the right to control the use of the identified asset.

The Company leases equipment and office space pursuant to net operating leases. Operating leases where the Company is the lessee are included in *"Operating lease right of use assets"* and *"Operating lease liabilities"* on the consolidated balance sheets. The lease liabilities are initially and subsequently measured at the present value of the unpaid lease payments at the lease commencement date. The Company has no leases that meet the criteria for classification as a finance lease.

Key estimates and judgments include how the Company determined (1) the discount rate used to discount the unpaid lease payments to present value, (2) lease term and (3) lease payments. ASC 842, *Leases* (ASC 842) requires a lessee to discount its unpaid lease payments using the interest rate implicit in the lease or, if that rate cannot be readily determined, its incremental borrowing rate. As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at the commencement date to determine the present value of lease payments. The incremental borrowing rate for a lease is the rate of interest the Company would have to pay on a collateralized basis to borrow an amount equal to the lease payments under similar terms. Additionally, the Company applies a portfolio approach to determine the discount rate (the incremental borrowing rate for leases with similar characteristics). The Company uses the implicit rate when readily determinable. The lease term includes the noncancellable period of the lease plus any additional periods covered by either a lessee option to extend (or not to terminate) the lease that the lessee is reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor. Lease payments included in the measurement of the lease asset or liability comprise the following, when applicable: fixed payments (including in-substance fixed payments), variable payments that depend on an index or rate, and the exercise price of a lessee option to purchase the underlying asset if the lessee is reasonably certain to exercise.

The right of use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for lease payments made at or before the lease commencement date, plus any initial direct costs incurred less any lease incentives received. For the Company's operating leases, the right of use asset is subsequently measured throughout the lease term at the carrying amount of the lease liability, plus initial direct costs, plus (minus) any prepaid (accrued) lease payments, less the unamortized balance of lease incentives received. Lease expense for lease payments is recognized on a straight-line basis over the lease term.

Variable lease payments associated with the Company's leases are recognized when the event, activity, or circumstance in the lease agreement on which those payments are assessed occurs. Variable lease payments, when applicable, are presented as *"Gathering and other," "Restructuring"* or *"General and administrative"* in the consolidated statements of operations in the same line item as the expense arising from the fixed lease payments on the operating leases.

The Company has lease agreements which include lease and nonlease components and the Company has elected to combine lease and nonlease components, when fixed, for all lease contracts. Nonlease components include common area maintenance charges on office leases and, when applicable, services associated with equipment leases. The Company determines whether the lease or nonlease component is the predominant component on a case-by-case basis.

The Company reviews its right of use assets for impairment in accordance with ASC 360. ASC 360 requires the Company to evaluate right of use assets for impairment as events occur or circumstances change that would more likely than not reduce the fair value below the carrying amount. If the carrying amount is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value.

The Company monitors for events or changes in circumstances that would require a reassessment of a lease. When a reassessment results in the remeasurement of a lease liability, an adjustment is made to the carrying amount of the corresponding right of use asset unless doing so would reduce the carrying amount of the right of use asset to an amount less than zero. In that case, the amount of the adjustment that would result in a negative right of use asset balance is recorded in the consolidated statements of operations.

The Company elected not to recognize right of use assets and lease liabilities for all short-term leases that have a lease term of 12 months or less. The Company recognizes the lease payments associated with its short-term leases when incurred. Variable lease payments associated with these leases are recognized and presented in the same manner as for all other leases.

The *"Operating lease right of use assets"* outstanding on the consolidated balance sheets as of December 31, 2021 and 2020 have initial lease terms of 2.3 and 5.0 years, respectively. Payments due under the lease contracts include fixed payments plus, in some instances, variable payments. The table below summarizes the Company's leases for the periods indicated (in thousands, except years and discount rate):

	Years Ended December 31,	
	2021	2020
Lease cost		
Operating lease costs	$ 444	$ 1,986
Short-term lease costs	3,152	16,650
Variable lease costs	375	913
Total lease costs	$ 3,971	$ 19,549
Other information		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 537	$ 2,350
Right-of-use assets obtained in exchange for new operating lease liabilities	841	—
Weighted-average remaining lease term - operating leases	1.9 years	0.5 years
Weighted-average discount rate - operating leases	4.29 %	3.70 %

As described in Note 1, *"Summary of Significant Events and Accounting Policies,"* the Company exercised a one-time early termination option under the lease agreement for the Company's office space in Denver, Colorado in May 2020 and paid a $1.3 million termination fee. The early termination option was deemed probable in May 2020 and was recognized in the Company's operating lease right of use asset and operating lease liability during the three months ended June 30, 2020. This reduced the Company's operating lease liability to $0.5 million, representing the remaining lease cost to be incurred from June 2020 through March 2021. The Company's abandonment of its office lease in Denver resulted in a $0.5 million impairment to its operating lease right of use asset presented as *"Restructuring"* in the consolidated statement of operations for the year ended December 31, 2020.

Future minimum lease payments associated with the Company's non-cancellable operating leases for office space and equipment as of December 31, 2021, are presented in the table below (in thousands):

	December 31, 2021
2022	$ 391
2023	359
2024	—
2025	—
2026	—
Thereafter	—
Total operating lease payments	750
Less: discount to present value	29
Total operating lease liabilities	721
Less: current operating lease liabilities	369
Noncurrent operating lease liabilities	$ 352

Practical Expedients

The Company elected the following practical expedients for transition to, and ongoing accounting under, ASC 842: (i) the Company does not separate lease and non-lease components of a contract, (ii) the Company does not reassess whether expired or existing contracts contain leases, nor does it reassess the lease classification for expired or existing leases and does not reassess whether previously capitalized initial direct costs would qualify for capitalization under ASC 842, (iii) the Company applies a single discount rate to a portfolio of leases with reasonably similar characteristics and (iv) the Company does not assess whether existing or expired land easements that were previously accounted for as leases are or contain a lease under ASC 842.

3. OPERATING REVENUES

Revenue Recognition

Revenue is measured based on consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. Taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction that are collected by the Company from a customer are excluded from revenue. Revenues from the sale of crude oil, natural gas and natural gas liquids are recognized, at a point in time, when a performance obligation is satisfied by the transfer of control of the commodity to the customer. Because the Company's performance obligations have been satisfied and an unconditional right to consideration exists as of the balance sheet date, the Company recognized amounts due from contracts with customers of $35.1 million and $24.5 million as of December 31, 2021 and 2020, respectively, as *"Accounts receivable"* and *"Other assets"* on the consolidated balance sheets.

Substantially all of the Company's revenues are derived from single basin operations, the Delaware Basin in Pecos, Reeves, Ward and Winkler Counties, Texas. The following table disaggregates the Company's revenues by major product, in order to depict how the nature, timing, and uncertainty of revenue and cash flows are affected by economic factors in the Company's single basin operations, for the periods indicated (in thousands):

	Years Ended December 31,	
	2021	2020
Operating revenues:		
Oil, natural gas and natural gas liquids sales:		
Oil	$ 213,512	$ 125,985
Natural gas	35,248	5,818
Natural gas liquids	35,394	14,972
Total oil, natural gas and natural gas liquids sales	284,154	146,775
Other	1,051	1,514
Total operating revenues	$ 285,205	$ 148,289

Oil Sales

The Company generally markets its crude oil production directly to the customer using two methods. Under the first method, crude oil is sold at the wellhead at an index price, averaged over the daily settlement prices for a production month, and adjusted for pricing differentials and other deductions. Revenue is recognized at the wellhead, where control of the crude oil transfers to the customer, at the net price received. Under the second method, crude oil is delivered to the customer at a contractual delivery point at which the customer takes custody, title and risk of loss of the product. The Company receives a specified index price from the customer, averaged over the daily settlement prices for a production month, and net of applicable market-related adjustments. Revenue is recognized when control of the crude oil transfers at the delivery point at the net price received.

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Settlement statements for the Company's crude oil production are typically received within the month following the date of production and therefore the amount of production delivered to the customer and the price that will be received for that production are known at the time the revenue is recorded. Payment under the Company's crude oil contracts is typically due on or before the 20th day of the month following the delivery month.

Natural Gas and Natural Gas Liquids Sales

The Company evaluates its natural gas gathering and processing arrangements in place with midstream companies to determine when control of the natural gas is transferred. Under contracts where it is determined that control of the natural gas transfers at the wellhead, any fees incurred to gather or process the unprocessed natural gas are treated as a reduction of the sales price of unprocessed natural gas, and therefore revenues from such transactions are presented on a net basis. Under contracts where it is determined that control of the natural gas transfers at the tailgate of the midstream entity's processing plant, revenues are presented on a gross basis for amounts expected to be received from the midstream company or third party purchasers through the gathering and treating process and presented as *"Natural gas"* or *"Natural gas liquids"* and any fees incurred to gather or process the natural gas are presented separately as *"Gathering and other"* on the consolidated statements of operations.

Under certain contracts, the Company may elect to take its residue gas and/or natural gas liquids in-kind at the tailgate of the midstream entity's processing plant. The Company then sells the products to a customer at contractual delivery points at prices based on an index. In these instances, revenues are presented on a gross basis and any fees incurred to gather, process or transport the commodities are presented separately as *"Gathering and other"* on the consolidated statements of operations.

Settlement statements for the Company's natural gas and natural gas liquids production are typically received 30 days after the date of production and therefore the Company estimates the amount of production delivered to the customer and the price that will be received for that production. The majority of the Company's natural gas and natural gas liquids prices are based on daily average pricing for the month. Historically, differences between the Company's estimates and the actual revenue received have not been material. Payment under the Company's natural gas gathering and processing contracts is typically due on or before the fifth day of the second month following the delivery month.

Practical Expedients

The Company does not disclose the transaction price of unsatisfied performance obligations for i) contracts with an original expected duration of one year or less and ii) contracts where variable consideration is allocated entirely to a wholly unsatisfied performance obligation (each unit of product typically represents a separate performance obligation, and therefore, future volumes under the Company's long-term contracts are wholly unsatisfied).

4. DIVESTITURES

Northern West Quito Assets

On December 18, 2020, the Company sold certain oil and gas properties and related assets located in Ward County, Texas (the North West Quito Assets) to Point Energy Partners Operating, LLC for a total adjusted sales price of $25.9 million in cash. The effective date of the transaction was October 1, 2020. Proceeds from the sale were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded. The Company used the net proceeds from the sale to repay amounts then outstanding under the Company's Senior Credit Agreement and for general corporate purposes.

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5. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties as of December 31, 2021 and 2020 consisted of the following (in thousands):

	December 31, 2021	December 31, 2020
Subject to depletion	$ 569,886	$ 509,274
Not subject to depletion:		
Exploration and extension wells in progress	—	—
Other capital costs:		
Incurred in 2021	1,427	—
Incurred in 2020	983	983
Incurred in 2019(1)	61,895	74,511
Incurred in 2018 and prior	—	—
Total not subject to depletion	64,305	75,494
Gross oil and natural gas properties	634,191	584,768
Less accumulated depletion	(339,776)	(295,163)
Net oil and natural gas properties	$ 294,415	$ 289,605

(1) In 2019, with the adoption of fresh-start accounting, the Company's unevaluated properties were recorded at fair value.

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, treating equipment and gathering support facilities costs, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs are charged to expense. Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production for the current period to total reserve volumes of evaluated properties as of the beginning of the period. Depletion expense was $44.6 million and $60.5 million for the year ended December 31, 2021 and 2020, respectively. Depletion expense is recorded in *"Depletion, depreciation and accretion"* in the Company's consolidated statements of operations.

Additionally, the Company assesses all properties classified as unevaluated property on a quarterly basis for possible impairment. The Company assesses properties on an individual basis or as a group, if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the full cost ceiling test limitation. For the three months ended September 30, 2020, the Company transferred approximately $23.6 million of unevaluated property costs to the full cost pool. These transfers of unevaluated property to the full cost pool in 2020 were the result of the Company's intent to focus available capital on Monument Draw.

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The ceiling test value of the Company's reserves was calculated based on the following prices:

	West Texas Intermediate (per barrel) (1)	Henry Hub (per MMBtu) (1)
December 31, 2021	$ 66.55	$ 3.60
December 31, 2020	39.54	1.99

(1) *Unweighted average of the first day of the 12-months ended spot price, adjusted by lease or field for quality, transportation fees, and regional price differentials.*

The Company's net book value of oil and natural gas properties in 2021 did not exceed the ceiling amount. The Company's net book value of oil and natural gas properties at June 30, September 30, and December 31, 2020 exceeded the ceiling amount and the Company recorded full cost ceiling test impairments before income taxes of $60.1 million, $128.3 million, and $26.7 million, respectively, for those periods, or $215.1 million for the year ended December 31, 2020. The ceiling test impairments during 2020 were primarily driven by decreases in the first-day-of-the-month 12-month average prices for crude oil used in the ceiling test calculation. Additionally, during the three months ended September 30, 2020, the transfer of unevaluated property costs to the full cost pool, as discussed above, also contributed to the impairment recorded for the period. During the three months ended December 31, 2020, proved undeveloped reserves additions as a result of changes to the Company's five year development plan partially offset the impact on the impairment of the average price decline for the period.

Full cost ceiling test impairments are recorded in *"Full cost ceiling impairment"* in the Company's consolidated statements of operations and in *"Accumulated depletion"* in the Company's consolidated balance sheets.

Changes in commodity prices, production rates, levels of reserves, future development costs, transfers of unevaluated properties to the full cost pool, capital spending, and other factors will determine the Company's ceiling test calculation and impairment analyses in future periods.

6. DEBT

As of December 31, 2021 and 2020, the Company's debt consisted of the following (in thousands):

	December 31, 2021	December 31, 2020
Term loan credit facility(1)	$ 181,565	$ —
Senior revolving credit facility	—	158,000
Paycheck Protection Program loan	85	2,209
Total debt, net	181,650	160,209
Current portion of Paycheck Protection Program loan	85	1,720
Total long-term debt, net	$ 181,565	$ 158,489

(1) *Amount is net of $14.2 million unamortized debt issuance costs at December 31, 2021. Amount also excludes $4.2 million allocated to the change of control call option embedded derivative. Refer to "Term Loan Credit Facility" below for further details.*

Term Loan Credit Facility

On November 24, 2021, the Company and its wholly owned subsidiary, Halcón Holdings, LLC (Borrower) entered into an Amended and Restated Senior Secured Credit Agreement (Term Loan Agreement) with Macquarie Bank

Limited, as administrative agent, and certain other financial institutions party thereto, as lenders. The Term Loan Agreement amends and restates in its entirety the Senior Credit Agreement as discussed below. Pursuant to the Term Loan Agreement, the lenders have agreed to loan the Company (i) $200.0 million, which was funded on November 24, 2021 and was partially used to refinance all amounts owed under the Senior Credit Agreement; (ii) up to $20.0 million, available to be drawn up to 18 months from November 24, 2021, subject to the satisfaction of certain conditions; and (iii) up to $15.0 million, which amount will be available to be drawn from the date certain wells included in the approved plan of development (APOD) are deemed producing APOD wells until up to 18 months after November 24, 2021, subject to the satisfaction of certain conditions. An additional $5.0 million is available for the issuance of letters of credit. The maturity date of the Term Loan Agreement is November 24, 2025. Until such maturity date, borrowings under the Term Loan Agreement shall bear interest at a rate per annum equal to LIBOR (or another applicable reference rate, as determined pursuant to the provisions of the Term Loan Agreement) plus an applicable margin of 7.00%.

The Company may elect, at its option, to prepay any borrowing outstanding under the Term Loan Agreement subject to the following prepayment premiums:

Period	Premium
Months 0 - 12	Make-whole amount equal to 12 months of interest plus 2.00%
Months 13 - 24	2.00%
Months 25 - 36	1.00%
Months 37 - 48	0.00%

The Company may be required to make mandatory prepayments of the loans under the Term Loan Agreement in connection with the incurrence of non-permitted debt, certain asset sales, and with excess cash on hand in excess of certain maximum levels. For each fiscal quarter after January 1, 2023, the Company shall make mandatory prepayments when the Consolidated Cash Balance, as defined in the Term Loan Agreement, exceeds $20.0 million. Until December 31, 2024, the forecasted APOD capital expenditures for the succeeding fiscal quarter are excluded for purposes of determining the Consolidated Cash Balance.

The Company is required to make scheduled amortization payments in the aggregate amount of $120.0 million from the fiscal quarter ending March 31, 2023 through the fiscal quarter ending September 30, 2025. Amounts outstanding under the Term Loan Agreement are guaranteed by certain of the Borrower’s direct and indirect subsidiaries and secured by a security interest in substantially all of the assets of the Borrower and such direct and indirect subsidiaries, and of the equity interests of the Borrower held by the Company. As part of the Term Loan Agreement there are certain restrictions on the transfer of assets, including cash, to Battalion from the guarantor subsidiaries.

The Term Loan Agreement also contains certain financial covenants, including the maintenance of (i) an Asset Coverage Ratio (as defined in the Term Loan Agreement) of not less than (A) 1.50 to 1.00 as of December 31, 2021 and March 31, 2022, (B) 1.60 to 1.00 as of June 30, 2022, (C) 1.70 to 1.00 as of September 30, 2022, and (D) 1.80 to 1.00 as of December 31, 2022 and each fiscal quarter thereafter, (ii) a Total Net Leverage Ratio (as defined in the Term Loan Agreement) of not greater than (A) 3.25 to 1.00 as of December 31, 2021 through and including June 30, 2022, (B) 3.00 to 1.00 as of September 30, 2022 and December 31, 2022, (C) 2.75 to 1.00 as of March 31, 2023, and (D) 2.50 to 1.00 as of each fiscal quarter thereafter, and (iii) a Current Ratio (as defined in the Term Loan Agreement) of not less than 1.00 to 1.00, each determined as of the last day of any fiscal quarter period. As of December 31, 2021, the Company was in compliance with the financial covenants under the Term Loan Agreement.

The Term Loan Agreement also contains an APOD for the Company’s Monument Draw acreage through the drilling and completion of certain wells. The Term Loan Agreement contains a proved developed producing production test and an APOD economic test which the Company must maintain compliance with otherwise, subject to any available remedies or waivers, the Company is required to immediately cease making expenditures in respect of the APOD other than any expenditures deemed necessary by the Company in respect of no more than six additional APOD wells.

The Term Loan Agreement also contains certain events of default, including non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy.

At December 31, 2021, the Company had $200.0 million indebtedness outstanding, approximately $0.3 million letters of credit outstanding and $35.0 million in delayed draw term loans available to be drawn under the Term Loan Agreement, subject to the satisfaction of certain conditions defined in the agreement.

In conjunction with the Term Loan Agreement, the Company agreed to pay a premium to the lenders upon a future change of control event in which a majority of the board of directors or the Chief Executive Officer or the Chief Financial Officer positions do not remain held by the same persons as before the change of control event (Change of Control Call Option). The premium is reduced over time through the payment of interest and certain fees. The Company determined that the Change of Control Call Option was an embedded derivative in accordance with FASB ASC 815, *Derivatives and Hedging*, concluded the embedded derivative was not clearly and closely related to the host debt instrument, and recorded the initial $4.2 million fair value separately on the consolidated balance sheet within *"Other noncurrent liabilities."* The Change of Control Call Option will be subsequently remeasured at fair value each reporting period with fair value changes recorded in *"Interest expense and other"* on the consolidated statements of operations. Refer to Note 7, "*Fair Value Measurements*," for a discussion of the valuation approach used, the significant inputs to the valuation, and for a reconciliation of the change in fair value of the Change of Control Call Option.

Senior Revolving Credit Facility

On October 8, 2019, the Company entered into a senior secured revolving credit agreement, as amended, (the Senior Credit Agreement) with Bank of Montreal, as administrative agent, and certain other financial institutions party thereto, as lenders, which refinanced the Company's debtor-in-possession junior secured term credit facility and its Predecessor senior secured revolving credit facility. The Senior Credit Agreement provided for a $750.0 million senior secured reserve-based revolving credit facility. A portion of the Senior Credit Agreement, in the amount of $25.0 million, was available for the issuance of letters of credit. The maturity date of the Senior Credit Agreement was October 8, 2024. The borrowing base was redetermined semi-annually, with the lenders and the Company each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base took into account the estimated value of the Company's oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. Amounts outstanding under the Senior Credit Agreement bore interest at specified margins over the base rate of 1.50% to 2.50% for ABR-based loans or at specified margins over LIBOR of 2.50% to 3.50% for Eurodollar-based loans. These margins fluctuated based on the Company's utilization of the facility. The Senior Credit Agreement was amended and restated by the Term Loan Agreement. Borrowings outstanding under the Senior Credit Agreement were repaid with proceeds from the Term Loan Agreement and the resulting charge of $0.1 million was recorded in *"Gain (loss) on extinguishment of debt"* in the consolidated statement of operations for the year ended December 31, 2021.

On May 10, 2021, the Company entered into the Fourth Amendment to Senior Secured Revolving Credit Agreement (the Fourth Amendment) which reduced the borrowing base to $185.0 million effective June 1, 2021 and further reduced the borrowing base to $175.0 million effective September 1, 2021. The Fourth Amendment also, among other things, (i) increased interest margins to 2.00% to 3.00% for ABR-based loans and 3.00% to 4.00% for Eurodollar-based loans, (ii) amended the covenant relating to the minimum mortgaged total value of proved borrowing base properties to increase the value from 90% to 95%, (iii) provided for direct reductions in the borrowing base in the event of asset dispositions in excess of $1.0 million per fiscal year or swap terminations and (iv) revised certain covenants and covenant-related baskets including, but not limited to, adding covenants prohibiting the designation of unrestricted subsidiaries and requiring prior consent from the lenders regarding asset dispositions or swap terminations in excess of the greater of $7.5 million or 3.5% of the then effective borrowing base.

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On September 24, 2021, the Company entered into the Fifth Amendment to Senior Secured Revolving Credit Agreement (the Fifth Amendment) which, among other things, modified the limits on swap agreements so as not to exceed, (i) from the period of the Fifth Amendment effective date through December 31, 2021, the percentage of the reasonably anticipated hydrocarbon production from proved developed producing reserves during such period hedged pursuant to secured swap agreements in place as of the Fifth Amendment effective date; (ii) for the fiscal year ending December 31, 2022, the greater of (a) the proved developed producing reserves during such fiscal year hedged pursuant to secured swap agreements in place as of the Fifth Amendment effective date and (b) 85% of the proved developed producing reserves during such fiscal year; and (iii) for the fiscal years ending December 31, 2023, December 31, 2024 and December 31, 2025, swap agreements not to exceed 85%, 70% and 60% of the proved developed producing reserves, respectively, during each fiscal year.

Paycheck Protection Program Loan

On April 16, 2020, the Company entered into a promissory note (the PPP Loan) for a principal amount of approximately $2.2 million from Bank of Montreal under the Paycheck Protection Program of the CARES Act, which is administered by the U.S. Small Business Administration (SBA). Pursuant to the terms of the CARES Act, the proceeds of the PPP Loan may be used for payroll costs, mortgage interest, rent or utility costs. The PPP Loan bears interest at a rate of 1.0% per annum and has a maturity date of April 16, 2022. As long as the Company made a timely application of forgiveness to the SBA, the Company was not required to make any payments under the PPP Loan until the forgiveness amount was communicated to the Company by the SBA. The Company applied for forgiveness of the amount due on the PPP Loan based on the use of the loan proceeds on eligible expenses in accordance with the terms of the CARES Act. Effective August 13, 2021, the principal amount of the Company’s PPP Loan was reduced to approximately $0.2 million by the SBA and the Company recorded a gain on the extinguishment of the forgiven portion of the PPP Loan and related accrued interest of $2.1 million. The gain is presented in *"Gain (loss) on extinguishment of debt"* in the consolidated statements of operations for the year ended December 31, 2021.

The PPP Loan contains certain events of default including non-payment, breach of representations and warranties, cross-defaults to other loans with the lender or to material indebtedness, voluntary or involuntary bankruptcy, judgments and change in control.

Debt Maturities

Aggregate maturities required on debt at December 31, 2021 due in future years are as follows (in thousands):

2022	$ 85
2023	35,000
2024	50,000
2025	115,000
2026	—
Thereafter	—
Total	$ 200,085

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of debt and amortizes such costs over the lives of the respective debt. During the year ended December 31, 2021, the Company capitalized approximately $14.6 million of debt issuance costs related to the Term Loan Agreement.

At December 31, 2021, the Company had $14.2 million of unamortized debt issuance costs.

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7. FAIR VALUE MEASUREMENTS

Pursuant to ASC 820, *Fair Value Measurement* (ASC 820), the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for any period presented. The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2021 and 2020 (in thousands):

	December 31, 2021			
	Level 1	Level 2	Level 3	Total
Assets				
Assets from derivative contracts	$ —	$ 3,898	$ —	$ 3,898
Liabilities				
Liabilities from derivative contracts	$ —	$ 65,466	$ —	$ 65,466

	December 31, 2020			
	Level 1	Level 2	Level 3	Total
Assets				
Assets from derivative contracts	$ —	$ 12,568	$ —	$ 12,568
Liabilities				
Liabilities from derivative contracts	$ —	$ 26,416	$ —	$ 26,416

Derivative contracts listed above as Level 2 include fixed-price swaps, collars, puts, calls, basis swaps and WTI NYMEX rolls that are carried at fair value. The Company records the net change in the fair value of these positions in *"Net gain (loss) on derivative contracts"* in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted market prices and implied volatility factors related to changes in the forward curves. See Note 8, *"Derivative and Hedging Activities,"* for additional discussion of derivatives.

The Company's derivative contracts are with major financial institutions with investment grade credit ratings which are believed to have minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts; however, the Company does not anticipate such nonperformance.

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As discussed in Note 6, *"Debt,"* the Company recorded the Change of Control Call Option separately at fair value on the consolidated balance sheets in *"Other noncurrent liabilities."* The valuation of the Change of Control Call Option includes significant inputs such as the timing and probability of discrete potential exit scenarios, forward LIBOR curves, and discount rates based on implied and market yields. The following table sets forth a reconciliation of the changes in fair value of the Change of Control Call Option classified as Level 3 in the fair value hierarchy (in thousands):

	Change of Control Call Option
Balance at November 24, 2021	$ 4,216
Change in fair value	(213)
Balance at December 31, 2021	$ 4,003

The estimated fair value of cash and cash equivalents, restricted cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Term Loan Agreement and Senior Credit Agreement approximates carrying value because the interest rates approximate current market rates.

The Company follows the provisions of ASC 820, for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. These provisions apply to the Company's initial recognition of asset retirement obligations for which fair value is used. The asset retirement obligation estimates are derived from historical costs and management's expectation of future cost environments; and therefore, the Company has designated these liabilities as Level 3. See Note 9, *"Asset Retirement Obligations,"* for a reconciliation of the beginning and ending balances of the liability for the Company's asset retirement obligations.

8. DERIVATIVE AND HEDGING ACTIVITIES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. In accordance with the Company's policy and the requirements under the Term Loan Agreement, it generally hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. Derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company's hedge policies and objectives may change significantly as its operational profile changes. The Company does not enter into derivative contracts for speculative trading purposes.

It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial or commodity hedging institutions deemed by management as competent and competitive market makers. As of December 31, 2021, the Company did not post collateral under any of its derivative contracts as they are secured under the Company's Term Loan Agreement.

The Company's crude oil and natural gas derivative positions at any point in time may consist of fixed-price swaps, costless put/call collars, basis swaps and WTI NYMEX rolls. Fixed-price swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract and a purchased put that establishes a minimum price and are generally utilized less frequently by the Company than fixed-price swaps. Basis swaps effectively lock in a price differential between regional prices (i.e. Midland) where the product is sold and the relevant pricing index under which the oil production is hedged (i.e. Cushing). WTI NYMEX roll agreements account for pricing adjustments to the trade month versus the delivery month for contract pricing. The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well

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as all payments and receipts on settled derivative contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820 and included in the consolidated balance sheets as assets or liabilities. The following table summarizes the location and fair value amounts of all derivative contracts in the consolidated balance sheets as of December 31, 2021 and 2020 (in thousands):

Derivatives not designated as hedging contracts under ASC 815	Balance sheet location	Asset derivative contracts December 31, 2021	Asset derivative contracts December 31, 2020	Balance sheet location	Liability derivative contracts December 31, 2021	Liability derivative contracts December 31, 2020
Commodity contracts	Current assets - assets from derivative contracts	$ 1,383	$ 8,559	Current liabilities - liabilities from derivative contracts	$ (58,322)	$ (22,125)
Commodity contracts	Other noncurrent assets - assets from derivative contracts	2,515	4,009	Other noncurrent liabilities - liabilities from derivative contracts	(7,144)	(4,291)
Total derivatives not designated as hedging contracts under ASC 815		$ 3,898	$ 12,568		$ (65,466)	$ (26,416)

The following table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivative contracts in the Company's consolidated statements of operations (in thousands):

Derivatives not designated as hedging contracts under ASC 815	Location of gain or (loss) recognized in income on derivative contracts	Amount of gain or (loss) recognized in income on derivative contracts for the Years Ended December 31, 2021	2020
Commodity contracts:			
Unrealized gain (loss) on commodity contracts	Other income (expenses) - net gain (loss) on derivative contracts	$ (47,721)	$ (6,143)
Realized gain (loss) on commodity contracts	Other income (expenses) - net gain (loss) on derivative contracts	(77,898)	44,902
Total net gain (loss) on derivative contracts		$ (125,619)	$ 38,759

During the year ended December 31, 2020, the Company terminated certain derivative contracts in advance of their natural expiration dates and received net proceeds of approximately $22.9 million, which were recorded in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

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At December 31, 2021, the Company had the following open crude oil and natural gas derivative contracts:

Instrument	2022	2023	2024	2025	2026
Crude oil fixed-price swap:					
Total volumes (Bbls)	2,504,249	1,937,165	1,388,920	988,260	29,810
Weighted average price	$ 50.19	$ 65.35	$ 60.67	$ 59.59	$ 59.61
Crude oil basis swap:					
Total volumes (Bbls)	2,278,848	1,937,165	1,388,920	988,260	29,810
Weighted average price	$ 0.47	$ 0.25	$ 0.23	$ 0.16	$ 0.10
Crude oil WTI NYMEX roll:					
Total volumes (Bbls)	2,286,598	1,937,165	1,388,920	988,260	29,810
Weighted average price	$ 0.01	$ 0.50	$ 0.27	$ 0.10	$ -
Natural gas fixed-price swap:					
Total volumes (MMBtu)	3,277,420	3,622,200	2,428,150	2,250,650	
Weighted average price	$ 3.60	$ 3.34	$ 3.05	$ 2.95	
Natural gas producer two-way collar:					
Total volumes (MMBtu)	2,963,124	1,389,500	1,078,000	315,000	
Weighted average price (call)	$ 3.07	$ 5.05	$ 4.58	$ 3.88	
Weighted average price (put)	$ 2.66	$ 3.41	$ 3.00	$ 3.00	
Natural gas basis swap:					
Total volumes (MMBtu)	6,240,544	5,011,700	3,506,150	2,565,650	
Weighted average price	$ (0.36)	$ (0.58)	$ (0.59)	$ (0.50)	

The Company presents the fair value of its derivative contracts at the gross amounts in the consolidated balance sheets. The following table shows the potential effects of master netting arrangements on the fair value of the Company's derivative contracts at December 31, 2021 and 2020 (in thousands):

	Derivative Assets		Derivative Liabilities	
Offsetting of Derivative Assets and Liabilities	**December 31, 2021**	**December 31, 2020**	**December 31, 2021**	**December 31, 2020**
Gross amounts presented in the consolidated balance sheet	$ 3,898	$ 12,568	$ (65,466)	$ (26,416)
Amounts not offset in the consolidated balance sheet	(3,898)	(8,968)	3,898	8,968
Net amount	$ —	$ 3,600	$ (61,568)	$ (17,448)

The Company enters into an International Swap Dealers Association Master Agreement (ISDA) with each counterparty prior to a derivative contract with such counterparty. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency.

9. ASSET RETIREMENT OBLIGATIONS

The Company records an asset retirement obligation (ARO) on oil and natural gas properties when it can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. The Company records the ARO liability on the consolidated balance sheets and capitalizes the cost in *"Oil and natural gas properties"* during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *"Depletion, depreciation and accretion"* expense in the consolidated statements of operations. The additional capitalized costs are depreciated on a unit-of-production basis.

The Company recorded the following activity related to its ARO liability (inclusive of the current portion) (in thousands):

Liability for asset retirement obligations as of December 31, 2019	$	10,590
Liabilities settled and divested (1)		(1,132)
Additions		488
Accretion expense		585
Revisions in estimated cash flows		52
Liability for asset retirement obligations as of December 31, 2020	$	10,583
Additions		111
Accretion expense		477
Revisions in estimated cash flows		725
Liability for asset retirement obligations as of December 31, 2021	$	11,896

(1) *See Note 4, "Divestitures," for additional information on the Company's divestiture activities.*

10. COMMITMENTS AND CONTINGENCIES

Commitments

As of December 31, 2021, the Company has a minimum volume commitment with a third party for the treating of sour gas production through June 30, 2022. The future payments associated with the minimum volume commitment are approximately $4.8 million.

As of December 31, 2021, the Company has an active drilling rig commitment of approximately $2.6 million that will be incurred in 2022. Termination of the active drilling rig commitment would require an early termination penalty of $0.6 million, which would be in lieu of paying the active drilling rig commitment of $2.6 million.

The Company has entered into various long-term gathering, transportation and sales contracts with respect to its oil and natural gas production from the Delaware Basin in West Texas. As of December 31, 2021, the Company had in place two long-term crude oil contracts and 12 long-term natural gas contracts in this area and the sales prices under these contracts are based on posted market rates. Under the terms of these contracts, the Company has committed a substantial portion of its production from this area for periods ranging from one to twenty years from the date of first production.

Contingencies

In addition to the matters described below, from time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. While the outcome and impact of currently pending legal proceedings cannot be determined, the Company's management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material effect on the Company's consolidated operating results, financial position or cash flows.

Surface owners of properties in Louisiana, where the Company formerly operated, often file lawsuits or assert claims against oil and gas companies claiming that operators and working interest owners are liable for environmental damages arising from operations conducted on the leased properties. These damages are frequently measured by the cost to restore the leased properties to their original condition. Currently and in the past, the Company has been party to such matters in Louisiana. With regard to pending matters, the overall exposure is not currently determinable. The Company intends to vigorously oppose these claims.

On February 26, 2019, a subsidiary of the Company was ordered to pay $9.1 million in a judgment entered by The Court of Common Pleas of Mercer County, Pennsylvania in a litigation matter captioned Vodenichar, et al., v. Halcón Energy Properties, Inc. et al., No. 2013-0512, arising from a dispute over whether the subsidiary complied with the terms of a letter of intent related to the leasing of acreage. The Court of Common Pleas of Mercer County, Pennsylvania marked the judgment as satisfied on February 3, 2020 and the Company considers this contingency resolved.

11. STOCKHOLDERS' EQUITY

Common Stock

On October 8, 2019, upon emergence from chapter 11 bankruptcy, the Successor Company filed an amended and restated certificate of incorporation with the Delaware Secretary of State to provide for, among other things, (i) the total number of shares of all classes of capital stock that the Successor Company has the authority to issue is 101,000,000 of which 100,000,000 shares are common stock, par value $0.0001 per share and 1,000,000 shares are preferred stock, par value $0.0001 per share and (ii) a restriction on the Successor Company from issuing any non-voting equity securities in violation of Section 1123(a)(6) of chapter 11 of title 11 of the United States Code. In addition, pursuant to the Company's certificate of incorporation, effective at the 2021 annual meeting of stockholders, the board ceased to be divided into two classes, and the provision for the right of removal of any directors designated as a Group II director by an increased voting threshold from a majority to 85% of the shares then entitled to vote at an election of directors shares expired.

Warrants

On October 8, 2019, the Company entered into a warrant agreement (the Warrant Agreement) with Broadridge Corporate Issuer Solutions, Inc. as the warrant agent, pursuant to which the Company issued three series of warrants (the Series A Warrants, the Series B Warrants and the Series C Warrants and together, the Warrants, and the holders thereof, the Warrant Holders), on a pro rata basis to pre-emergence holders of the predecessor Company's common stock pursuant to the Company's plan of reorganization.

Each Warrant represents the right to purchase one share of common stock at the applicable exercise price, subject to adjustment as provided in the Warrant Agreement and as summarized below. On October 8, 2019, the Company issued (i) Series A Warrants to purchase an aggregate of 1,798,322 shares of common stock, with an initial exercise price of $40.17 per share, (ii) Series B Warrants to purchase an aggregate of 2,247,985 shares of common stock, with an initial exercise price of $48.28 per share and (iii) Series C Warrants to purchase an aggregate of 2,890,271 shares of common stock, with an initial exercise price of $60.45 per share. Each series of Warrants issued under the Warrant Agreement has a three-year term, expiring on October 8, 2022. The strike price of each series of Warrants issued under the Warrant Agreement increases monthly at an annualized rate of 6.75%, compounding monthly, as provided in the Warrant Agreement. As of December 31, 2021, the Company had 1.8 million Series A, 2.2 million Series B and 2.9 million Series C warrants outstanding with corresponding exercise prices of $44.95, $54.34 and $68.42, respectively.

The Warrants do not grant the Warrant Holder any voting or control rights or dividend rights, or contain any negative covenants restricting the operation of the Company's business.

Incentive Plans

On January 29, 2020, the Company's board of directors adopted the 2020 Long-Term Incentive Plan (the Plan) with an effective date of January 1, 2020 in which an aggregate of approximately 1.5 million shares of the Company's common stock were available for grant pursuant to awards under the Plan. On June 8, 2021, Amendment No. 1 to the Plan to increase, by 0.3 million shares, the maximum number of shares of common stock that may be issued thereunder, i.e., a maximum of approximately 1.8 million shares, became effective. As of December 31, 2021 and 2020, a maximum of 0.5 million and 0.2 million shares, respectively, of the Company's common stock remained reserved for issuance under the Plan.

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The Company accounts for stock-based payment accruals under authoritative guidance on stock compensation. The guidance requires all stock-based payments to employees and directors, including grants of stock options and restricted stock, to be recognized in the financial statements based on their fair values. The Company has elected not to apply a forfeiture estimate and will recognize a credit in compensation expense to the extent awards are forfeited.

For the years ended December 31, 2021 and 2020, the Company recognized $2.0 million and $2.6 million, respectively, related to stock-based compensation recorded as a component of *"General and administrative"* on the consolidated statements of operations.

Stock Options

From time to time, the Company grants stock options under the Plan covering shares of common stock to employees of the Company. Stock options, when exercised, are settled through the payment of the exercise price in exchange for new shares of stock underlying the option. Awards granted under the Plan typically vest over a four year period at a rate of one-fourth on the annual anniversary date of the grant and expire seven years from the date of grant.

No stock options were granted during the year ended December 31, 2021. At December 31, 2021, the Company had $0.4 million of unrecognized compensation expense related to non-vested stock-options to be recognized over a weighted-average period of 1.2 years.

The aggregate grant date fair value of options granted during the year ended December 31, 2020 was $1.9 million. At December 31, 2020, the Company had $0.9 million of unrecognized compensation expense related to non-vested stock-options to be recognized over a weighted-average period of 1.7 years.

The following table sets forth the stock option transactions for the periods indicated:

	Number	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value[(1)] (In thousands)	Weighted Average Remaining Contractual Life (Years)
Outstanding at December 31, 2019	—	$ —	$ —	—
Granted	557,844	28.32		
Exercised	—	—		
Forfeited	(79,692)	28.32		
Outstanding at December 31, 2020	478,152	28.32	$ —	6.2
Granted	—	—		
Exercised	—	—		
Forfeited	—	—		
Outstanding at December 31, 2021	478,152	$ 28.32	$ —	5.2

(1) *The period end intrinsic value of stock options was calculated as the amount by which the closing market price on December 31, 2021 and 2020 of the underlying stock exceeded the exercise price of the option.*

Options outstanding at December 31, 2021 consisted of the following:

	Outstanding				Exercisable[(1)]			
Range of Grant Prices Per Share	Number	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Life (Years)	Number	Weighted Average Exercise Price per Share	Aggregate Intrinsic Value	Weighted Average Remaining Contractual Life (Years)
$ 18.91	159,384	$ 18.91	5.2	—	$ —	$ —	—
28.23	159,384	28.23	5.2	—	—	—	—
37.83	159,384	37.83	5.2	—	—	—	—

(1) *At December 31, 2021, none of the Company's stock options were exercisable due to service performance conditions or options exercise prices above current market value of the underlying stock.*

The assumptions used in calculating the Black-Scholes-Merton valuation model fair value of the Company's stock options for year ended December 31, 2020 are set forth in the following table:

	Year Ended December 31, 2020
Weighted average value per option granted during the period	$ 3.36
Assumptions:	
Stock price volatility[(1)]	61.87 %
Risk free rate of return	1.21 %
Expected term	4.75 years

(1) *Due to the Company's limited historical data, expected volatility was estimated using volatilities of similar entities whose share or option prices and assumptions were publicly available.*

Restricted Stock

From time to time, the Company grants shares of restricted stock units (RSUs) under the Plan to employees of the Company. Under the Plan, employee RSUs will vest and convert to shares typically over a four year period at a rate of one-fourth on the annual anniversary date of the grant or when the performance or market conditions described below occur.

During the year ended December 31, 2021, the Company granted less than 0.1 million shares of RSUs which will vest over four years at a rate of one-fourth on the annual anniversary date of the grant. The aggregate grant date fair value of these RSUs was $0.1 million. At December 31, 2021, the Company had $2.2 million of unrecognized compensation expense related to non-vested RSU awards to be recognized over a weighted average period of 1.8 years.

During the year ended December 31, 2020, the Company granted 1.0 million shares of RSUs with the vesting conditions and fair values described below under the Plan to employees of the Company. At December 31, 2020, the Company had $4.1 million of unrecognized compensation expense related to non-vested RSU awards to be recognized over a weighted-average period of 2.5 years.

- 0.4 million RSUs granted will vest over four years at a rate one-fourth on the annual anniversary of date of the grant. The aggregate grant date fair value of these RSUs was $5.0 million.
- 0.2 million RSUs granted will vest in full only upon achievement of certain business combination goals, as defined in the awards agreements. The aggregate grant date fair value of these RSUs was $2.1 million. As of December 31, 2021, a business combination, as defined in the awards agreements, had not been

consummated and was not considered probable. As such, no expense has been recognized for the RSUs with business combination vesting conditions.

- 0.4 million RSUs granted will vest in full or in part or may terminate based on the Company's total shareholder return relative to the total shareholder return of certain of its peer companies as defined in the awards agreements over the performance period ending on February 20, 2024. The aggregate grant date fair value of these RSUs was $2.3 million.

The following table sets forth the restricted stock transactions for the periods indicated:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value[1] (In thousands)
Unvested outstanding shares at December 31, 2019	—	$ —	$ —
Granted	987,590	9.46	
Vested	—	—	
Forfeited	(113,456)	9.36	
Unvested outstanding shares at December 31, 2020	874,134	$ 9.48	$ 3,287
Granted	12,000	8.00	
Vested	(95,994)	11.51	
Forfeited	(14,625)	11.89	
Unvested outstanding shares at December 31, 2021	775,515	$ 9.16	$ 2,914

(1) *The intrinsic value of restricted stock was calculated as the closing market price on December 31, 2021 and 2020 of the underlying stock multiplied by the number of restricted shares that would be issuable. The total fair value of shares vested was $1.1 million for the year ended December 31, 2021.*

The assumptions used in calculating the Monte Carlo valuation model fair value of the Company's RSUs with performance based vesting conditions for the year ended December 31, 2020 are set forth in the following table:

	Year Ended December 31, 2020
Weighted average value per performance based RSUs granted during the period	$ 6.13
Assumptions:	
Stock price volatility[1]	51.79 %
Risk free rate of return	1.22 %
Expected term	3.9 years

(1) *Due to the Company's limited historical data, expected volatility was estimated using volatilities of peer entities as defined in the award agreements whose share prices and assumptions were publicly available.*

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12. INCOME TAXES

Income tax benefit (provision) for the indicated periods is comprised of the following (in thousands):

	Years Ended December 31, 2021	Years Ended December 31, 2020
Current:		
Federal	$ —	$ —
State	—	—
	—	—
Deferred:		
Federal	—	—
State	—	—
	—	—
Total income tax benefit (provision)	$ —	$ —

The actual income tax benefit (provision) differs from the expected income tax benefit (provision) as computed by applying the United States federal corporate income tax rate of 21% for the periods indicated below, as follows (in thousands):

	Years Ended December 31, 2021	Years Ended December 31, 2020
Expected tax benefit (provision)	$ 5,947	$ 48,238
Change in valuation allowance and related items	57,845	(10,849)
Attribute reduction	(64,024)	(37,985)
Permanent adjustments	404	577
Employee retention credit	(153)	—
Other	(19)	19
Total income tax benefit (provision)	$ —	$ —

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The components of net deferred income tax assets (liabilities) recognized are as follows (in thousands):

	December 31, 2021	December 31, 2020
Deferred noncurrent income tax assets:		
Net operating loss carry-forwards	$ 135,454	$ 94,742
Built in loss adjustment Section 382	693	98,416
Capital loss carryforward	114,725	74,848
Stock-based compensation expense	1,870	1,448
Asset retirement obligations	2,447	2,347
Book-tax differences in property basis	148,008	199,170
Unrealized hedging transactions	12,929	2,908
Disallowed interest Section 163(j)	15,230	13,579
Basis difference in debt	—	1,687
Change of Control Call Option Embedded Derivative	841	—
Operating lease liability	151	85
Other	382	374
Gross deferred noncurrent income tax assets	432,730	489,604
Valuation allowance	(431,694)	(489,539)
Deferred noncurrent income tax assets	$ 1,036	$ 65
Deferred noncurrent income tax liabilities:		
Basis difference in debt	$ (885)	$ —
Lease right of use	(151)	(65)
Deferred noncurrent income tax liabilities	$ (1,036)	$ (65)
Net noncurrent deferred income tax assets (liabilities)	$ —	$ —

The amount of U.S. consolidated Net Operating Losses (NOLs) available as of December 31, 2021 after attribute reduction is estimated to be approximately $1.1 billion, but the amount after attribute reduction and the Section 382 limitation is $644.8 million. Of this amount, $105.6 million is subject to the 20 year carryforward period and will expire in 2037. The remaining $539.2 million may be carried forward indefinitely but is in part subject to a Section 382 limitation.

The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The Company considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. The Company evaluated possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies in making this assessment. As a result of the Company’s analysis, it was concluded that as of December 31, 2021, a valuation allowance should continue to be applied against the Company’s net deferred tax asset. The Company recorded a valuation allowance as of December 31, 2021 of $431.7 million, a decrease of $57.8 million from December 31, 2020. The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized.

The Company emerged from Chapter 11 Bankruptcy on October 8, 2019. Under the plan of reorganization, a substantial portion of the Company’s pre-petition debt securities were extinguished. 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 IRC provides that a debtor in bankruptcy may exclude CODI from taxable income but must first reduce its tax attributes by the amount any CODI realized as a result of the consummation of a plan of reorganization. The amount of CODI realized by a taxpayer is the adjusted issue price of any indebtedness discharged less the sum of (i) the amount of cash paid, (ii) the issue price of any new indebtedness issued and (iii) the fair market value of any other consideration, including equity, issued. As a result of the market value of equity upon emergence from chapter 11 bankruptcy proceedings, U.S. CODI was approximately $524.8 million, which reduced the value of the Company’s net operating losses and capital losses on January 1, 2020. The deferred tax balances disclosed above reflect the estimated impact of the attribute reduction on January 1, 2020.

IRC Section 382 provides an annual limitation with respect to the ability of a corporation to utilize its tax attributes, as well as certain built-in-losses, against future U.S. taxable income in the event of a change in ownership. The Company's emergence from chapter 11 bankruptcy proceedings is considered a change in ownership for purposes of IRC Section 382. The limitation under the IRC is based on the value of the corporation as of the emergence date. The ownership changes and resulting annual limitation resulted in the expiration of approximately $454.2 million of net operating losses generated prior to the emergence date. The expiration of these tax attributes was fully offset by a corresponding decrease in the Company's U.S. valuation allowance, which results in no net tax provision.

ASC 740, *Income Taxes* (ASC 740) prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company has no unrecognized tax benefits for the year ended December 31, 2021 and 2020.

Generally, the Company’s income tax years 2018 through 2021 remain open for federal purposes and are subject to examination by Federal tax authorities. The Company's income tax returns are also subject to audit by the tax authorities in Louisiana, Mississippi, North Dakota, Oklahoma, Texas, Pennsylvania, Ohio and certain other state taxing jurisdictions where the Company has, or previously had, operations. In certain jurisdictions the Company operates through more than one legal entity, each of which may have different open years subject to examination. The open years for state purposes can vary from the normal three year statue expiration period for federal purposes.

The Company recognizes interest and penalties accrued to unrecognized benefits in *"Interest expense and other"* in its consolidated statements of operations. For the year ended December 31, 2021 and 2020, the Company recognized no interest and penalties.

During 2020, the CARES Act and the Consolidated Appropriations Act of 2021 (the CAA) were signed into law. The CARES Act provides relief to corporate taxpayers by permitting a five-year carryback of 2018 to 2020 NOLs, removing the 80% limitation on the utilization of those NOLs, increasing the Section 163(j) 30% limitation on interest expense deductibility to 50% of adjusted taxable income for 2019 and 2020, and accelerates refunds for minimum tax credit carryforwards, as well as other provisions. The CAA extends various expiring tax provisions, clarifies that debt forgiven under the Paycheck Protection Program (PPP) is not included in gross income, clarifies that certain business expenses paid with forgiven PPP funds are tax deductible, as well as other tax provisions. Both the CARES Act and CAA did not have a material impact to the Company’s consolidated financial statements and related disclosures.

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13. EARNINGS PER SHARE

The following represents the calculation of earnings (loss) per share (in thousands, except per share amounts):

	Years Ended December 31, 2021	2020
Basic:		
Net income (loss) available to common stockholders	$ (28,317)	$ (229,707)
Weighted average basic number of common shares outstanding	16,261	16,204
Basic net income (loss) per common share	$ (1.74)	$ (14.18)
Diluted:		
Net income (loss) available to common stockholders	$ (28,317)	$ (229,707)
Weighted average basic number of common shares outstanding	16,261	16,204
Common stock equivalent shares representing shares issuable upon:		
Exercise of Series A Warrants	Anti-dilutive	Anti-dilutive
Exercise of Series B Warrants	Anti-dilutive	Anti-dilutive
Exercise of Series C Warrants	Anti-dilutive	Anti-dilutive
Exercise of stock options	Anti-dilutive	Anti-dilutive
Vesting of restricted stock units	Anti-dilutive	Anti-dilutive
Weighted average diluted number of common shares outstanding	16,261	16,204
Diluted net income (loss) per common share	$ (1.74)	$ (14.18)

Common stock equivalents, including warrants, stock options and restricted stock units, if considered issuable, totaling 7.7 million for the year ended December 31, 2021 were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive due to the net loss.

Common stock equivalents, including warrants, stock options and restricted stock units, if considered issuable, totaling 7.7 million shares for the year ended December 31, 2020 were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive due to the net loss.

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14. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following (in thousands):

	December 31, 2021	December 31, 2020
Accounts receivable, net:		
Oil, natural gas and natural gas liquids revenues	$ 34,110	$ 22,781
Joint interest accounts	2,503	8,543
Other	193	918
	$ 36,806	$ 32,242
Prepaids and other:		
Prepaids	$ 975	$ 892
Funds in escrow	390	1,740
Other	1	108
	$ 1,366	$ 2,740
Funds in escrow and other:		
Oil, natural gas and natural gas liquids revenues	$ 1,010	$ 1,720
Funds in escrow	1,227	581
Other	33	50
	$ 2,270	$ 2,351
Accounts payable and accrued liabilities:		
Trade payables	$ 25,315	$ 22,740
Accrued oil and natural gas capital costs	4,881	8,344
Revenues and royalties payable	22,763	16,412
Accrued interest expense	42	482
Accrued employee compensation	3,735	3,223
Accrued lease operating expenses	6,090	7,622
Other	—	105
	$ 62,826	$ 58,928

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

The proved reserves estimates reported herein for the years ended December 31, 2021, 2020 and 2019 have been independently evaluated by Netherland, Sewell, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland, Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland, Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland, Sewell reserves reports incorporated herein are Mr. Neil H. Little and Mr. Edward Roy III. Mr. Little, a Licensed Professional Engineer in the State of Texas (No. 117966), has been practicing consulting petroleum engineering at Netherland, Sewell since 2011 and has over nine years of prior industry experience. He graduated from Rice University in 2002 with a Bachelor of Science Degree in Chemical Engineering and from University of Houston in 2007 with a Master of Business Administration Degree. Mr. Roy, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 2364), has been practicing consulting petroleum geoscience at Netherland, Sewell since 2008 and has over 11 years of prior industry experience. He graduated from Texas Christian University in 1992 with a Bachelor of Science Degree in Geology and from Texas A&M University in 1998 with a Master of Science Degree in Geology. Netherland, Sewell has reported to the Company that both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; they are both proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The Company's board of directors has established an independent reserves committee composed of independent directors with experience in energy company reserve evaluations. The Company's independent engineering firm reports jointly to the reserves committee and to the Executive Vice President and Chief Operating Officer. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to the board of directors as to whether to approve the report prepared by the independent engineering firm. Mr. Daniel P. Rohling, the Company's Executive Vice President and Chief Operating Officer is primarily responsible for overseeing the preparation of the annual reserve report by Netherland, Sewell. He has approximately 15 years of oil and gas operations experience and earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University and is an active member of the Society of Petroleum Engineers.

The reserves information in this Annual Report on Form 10-K represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the Company's proved reserves will decline as reserves are produced.

The following tables illustrate changes in the Company's estimated net proved developed and proved undeveloped reserves for the periods indicated. The oil and natural gas liquids prices as of December 31, 2021, 2020 and 2019 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate spot price which equates to $66.55 per barrel, $39.54 per barrel and $55.85 per barrel, respectively. The natural gas prices as of December 31, 2021, 2020 and 2019 are based on the respective 12-month unweighted average of the first of the month prices of the Henry Hub spot price which equates to $3.60 per MMBtu, $1.99 per MMBtu and $2.58 per MMBtu, respectively. All prices are adjusted by lease or field for energy content, transportation fees, and market differentials. All prices are held constant in accordance with SEC guidelines. All proved reserves are located in the United States.

	Total Proved Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
Proved reserves, December 31, 2018 (Predecessor)	50,654	104,749	17,100	85,212
Extensions and discoveries	9,161	12,372	1,952	13,175
Production	(3,780)	(9,136)	(1,262)	(6,565)
Revision of previous estimates	(16,801)	(35,724)	(7,015)	(29,769)
Proved reserves, December 31, 2019 (Successor)	39,234	72,261	10,775	62,053
Extensions and discoveries	8,268	12,157	2,090	12,384
Production	(3,446)	(8,769)	(1,262)	(6,170)
Sale of minerals in place	(1,433)	(2,177)	(246)	(2,042)
Revision of previous estimates	(4,407)	5,034	718	(2,850)
Proved reserves, December 31, 2020 (Successor)	38,216	78,506	12,075	63,375
Extensions and discoveries	18,447	26,508	3,655	26,520
Production	(3,196)	(9,447)	(1,157)	(5,928)
Revision of previous estimates	5,265	29,398	1,747	11,913
Proved reserves, December 31, 2021 (Successor)	58,732	124,965	16,320	95,880

	Equivalent (Mboe)		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Proved reserves, December 31, 2018 (Predecessor)	39,869	45,343	85,212
Extensions and discoveries	2,813	10,362	13,175
Production	(6,565)	—	(6,565)
Transfers	10,213	(10,213)	—
Revision of previous estimates	(8,395)	(21,374)	(29,769)
Proved reserves, December 31, 2019 (Successor)	37,935	24,118	62,053
Extensions and discoveries	13	12,371	12,384
Production	(6,170)	—	(6,170)
Sale of minerals in place	(2,042)	—	(2,042)
Transfers	6,513	(6,513)	—
Revision of previous estimates	(17)	(2,833)	(2,850)
Proved reserves, December 31, 2020 (Successor)	36,232	27,143	63,375
Extensions and discoveries	7	26,513	26,520
Production	(5,928)	—	(5,928)
Transfers	2,104	(2,104)	—
Revision of previous estimates	9,995	1,918	11,913
Proved reserves, December 31, 2021 (Successor)	42,410	53,470	95,880

	Proved Developed Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2021	21,694	71,009	8,881	42,410
December 31, 2020	20,371	51,097	7,345	36,232
December 31, 2019	22,821	48,558	7,021	37,935

	Proved Undeveloped Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2021	37,038	53,956	7,439	53,470
December 31, 2020	17,845	27,409	4,730	27,143
December 31, 2019	16,413	23,703	3,754	24,118

The Company's proved reserves have been estimated using deterministic methods. At December 31, 2021, total proved reserves were approximately 95.9 MMBoe, a 32.5 MMBoe net increase over the previous year's estimate of 63.4 MMBoe. The net increase in total proved reserves was the result of additions and extensions of 26.5 MMBoe and positive revisions of 11.9 MMBoe due primarily to increases in SEC pricing, partially offset by production of 5.9 MMBoe.

At December 31, 2021, the Company's proved developed reserves were approximately 42.4 MMBoe, a 6.2 MMBoe net increase from the previous year's estimate of 36.2 MMBoe. The net increase in total proved reserves was the result of positive revisions of 10.0 MMBoe due to increases in SEC pricing and the development of 2.1 MMBoe (transferred from proved undeveloped), partially offset by production of 5.9 MMBoe.

At December 31, 2021, the Company's estimated proved undeveloped (PUD) reserves were approximately 53.5 MMBoe, a 26.4 MMBoe net increase from the previous year's estimate of 27.1 MMBoe. The net increase in total PUD reserves was the result of additions and extensions of 26.5 MMBoe and positive revisions of 1.9 MMBoe due to increases in SEC pricing, partially offset by development of 2.1 MMBoe. Of the 26.5 MMBoe of extensions and discoveries in PUD reserves, all are associated with drilling extensions in the Delaware Basin. None of the extensions and discoveries in PUD reserves in 2021 were associated with infill drilling activity.

At December 31, 2020, the Company's proved developed reserves were approximately 36.2 MMBoe, a 1.7 MMBoe net decrease from the previous year's estimate of 37.9 MMBoe. The net decrease in total proved reserves was the result of production of 6.2 MMBoe and sales of 2.0 MMBoe, partially offset by development of 6.5 MMBoe (transferred from proved undeveloped).

At December 31, 2020, the Company's estimated PUD reserves were approximately 27.1 MMBoe, a 3.0 MMBoe net increase from the previous year's estimate of 24.1 MMBoe. The net increase in total PUD reserves was the result of additions and extensions of 12.4 MMBoe, partially offset by development of 6.5 MMBoe and negative revisions of 2.8 MMBoe due primarily to decreases in SEC pricing. Of the 12.4 MMBoe of extensions and discoveries in PUD reserves, all are associated with drilling extensions in the Delaware Basin. None of the extensions and discoveries in PUD reserves in 2020 were associated with infill drilling activity.

At December 31, 2019, the Company's proved developed reserves were approximately 37.9 MMBoe, a 2.0 MMBoe net decrease from the previous year's estimate of 39.9 MMBoe. The net decrease in total proved reserves was the result of negative revisions of 8.4 MMBoe and production of 6.5 MMBoe, partially offset by additions and extensions of 2.8 MMBoe and development of 10.1 MMBoe (transferred from proved undeveloped). Negative revisions of 8.4 MMBoe primarily relate to changes in the Company's development plans to focus on Monument Draw and due to the effect of lower prices. Of the 2.8 MMBoe of extensions and discoveries in proved developed reserves, approximately 1.2 MMBoe are associated with infill drilling activity and 1.6 MMBoe are associated with drilling extensions in the Delaware Basin.

At December 31, 2019, the Company's estimated PUD reserves were approximately 24.1 MMBoe, a 21.2 MMBoe net decrease from the previous year's estimate of 45.3 MMBoe. The net decrease in total PUD reserves was the result of negative revisions of 21.4 MMBoe and development of 10.2 MMBoe, partially offset by additions and extensions of 10.4 MMBoe. The negative revisions to PUD reserves in 2019 were primarily attributable to the changes in the Company's development plans to focus on Monument Draw and due to the effect of lower prices. Of the 10.4 MMBoe of extensions and discoveries in PUD reserves, approximately 6.6 MMBoe are associated with infill drilling activity and 3.8 MMBoe are associated with drilling extensions in the Delaware Basin.

As of December 31, 2021 all of the Company's PUD reserves are planned to be developed within five years from the date they were initially recorded. During 2021, approximately $37.6 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

For wells classified as proved developed producing where sufficient production history existed, reserves were based on individual well performance evaluation and production decline curve extrapolation techniques. For undeveloped locations and wells that lacked sufficient production history, reserves were based on analogy to producing wells within the same area exhibiting similar geologic and reservoir characteristics, combined with volumetric methods. The volumetric estimates were based on geologic maps and rock and fluid properties derived from well logs, core data, pressure measurements, and fluid samples. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and volumetric estimates for each area or field. PUD locations were limited to areas of uniformly high quality reservoir properties, between existing commercial producers.

Reliable technologies were used to determine areas where PUD locations are more than one offset location away from a producing well. These technologies include seismic data, wire line openhole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic EURs from individual producing wells. The Company relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves. Out of total proved undeveloped reserves of 53.5 MMBoe at December 31, 2021, 37.7 MMBoe were associated with 39 gross PUD locations that were more than one offset location from a producing well.

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depletion, depreciation and accretion (in thousands):

	December 31, 2021	December 31, 2020	December 31, 2019
Evaluated oil and natural gas properties	$ 569,886	$ 509,274	$ 420,609
Unevaluated oil and natural gas properties	64,305	75,494	105,009
	634,191	584,768	525,618
Accumulated depletion	(339,776)	(295,163)	(19,474)
	$ 294,415	$ 289,605	$ 506,144

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

	Successor			Predecessor
	Years Ended December 31,		Period from October 2, 2019 through	Period from January 1, 2019 through
	2021	2020	December 31, 2019	October 1, 2019
Property acquisition costs, proved	$ —	$ 23	$ —	$ —
Property acquisition costs, unproved	—	—	—	2,809
Exploration and extension well costs	6,125	14,082	9,209	89,389
Development costs(1)	37,611	43,256	15,839	60,275
Total costs	$ 43,736	$ 57,361	$ 25,048	$ 152,473

(1) Excludes $5.7 million, $31.5 million, $11.3 million and $72.9 million for the years ended December 31, 2021 and 2020, the period from October 2, 2019 to December 31, 2019 and the period from January 1, 2019 to October 1, 2019, respectively, of development costs related to the Company's treating equipment and gathering support facilities.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following Standardized Measure of Discounted Future Net Cash Flows (Standardized Measure) has been developed utilizing ASC 932, *Extractive Activities—Oil and Gas* (ASC 932) procedures and based on oil and natural gas reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- future costs and selling prices will probably differ from those required to be used in these calculations;
- due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and
- future net revenues may be subject to different rates of income taxation.

At December 31, 2021, 2020 and 2019, as specified by the SEC, the prices for oil and natural gas used in this calculation were the unweighted 12-month average of the first day of the month prices, except for volumes subject to fixed price contracts. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor.

The Standardized Measure is as follows:

	Years Ended December 31,		
	2021	2020	2019
		(In thousands)	
Future cash inflows	$ 4,688,646	$ 1,660,950	$ 2,257,083
Future production costs	(1,947,781)	(911,099)	(1,207,370)
Future development costs	(540,596)	(315,078)	(261,747)
Future income tax expense	(725)	(1,459)	(1,577)
Future net cash flows before 10% discount	2,199,544	433,314	786,389
10% annual discount for estimated timing of cash flows	(1,123,889)	(223,918)	(377,514)
Standardized measure of discounted future net cash flows	$ 1,075,655	$ 209,396	$ 408,875

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following is a summary of the changes in the Standardized Measure for the Company's proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2021:

	Years Ended December 31,		
	2021	2020	2019
		(In thousands)	
Beginning of year	$ 209,396	$ 408,875	$ 853,567
Sale of oil and natural gas produced, net of production costs	(164,221)	(34,888)	(104,007)
Sales of minerals in place	—	(22,387)	—
Extensions and discoveries	268,319	17,127	71,585
Changes in income taxes, net	119	25	5,845
Changes in prices and costs	472,162	(231,791)	(306,466)
Previously estimated development costs incurred	28,208	68,135	85,538
Net changes in future development costs	1,760	3,867	26,742
Revisions of previous quantities	184,284	(30,757)	(266,538)
Accretion of discount	20,963	40,914	85,968
Changes in production rates and other	54,665	(9,724)	(43,359)
End of year	$ 1,075,655	$ 209,396	$ 408,875

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(f) and 15d-15(f), of the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures based on the *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013 as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2021 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Management has assessed our internal control over financial reporting as of December 31, 2021. The unqualified report of management thereon is included in Item 8. *Consolidated Financial Statements and Supplementary Data* of this Annual Report on Form 10-K and is incorporated by reference herein.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act, during the three months ended December 31, 2021 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2022 Annual Meeting of Stockholders.

The Company's Code of Conduct and Code of Ethics for the Principal Executive Officer and Senior Financial Officers can be found on the Company's website located at *www.battalionoil.com*. Any stockholder may request a printed copy of such materials by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least twelve months after the initial disclosure of such waiver.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2022 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Equity Compensation Plan Information

The following table sets forth certain information as of December 31, 2021 with respect to compensation plans (including individual compensation arrangements) under which our equity securities are authorized for issuance.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options and Rights (A)(1)	Weighted-Average Exercise Price of Outstanding Options and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(A))
Equity compensation plans approved by security holders.	—	$ —	—
Equity compensation plans not approved by security holders(2)	1,253,667	28.32	455,623
	1,253,667	$ 28.32	455,623

(1) Consists of 775,515 unvested RSUs and outstanding 478,152 stock options.

(2) The formation of the plan was approved by the Bankruptcy Court upon confirmation of our Plan of Reorganization and further approved by our board with an effective date of January 1, 2020.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2022 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2022 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2022 Annual Meeting of Stockholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements:

The consolidated financial statements of the Company and its subsidiaries and reports of independent registered public accounting firms listed in Section 8 of this Annual Report on Form 10-K are filed as a part of this Annual Report on Form 10-K.

(2) Consolidated Financial Statements Schedules:

All schedules are omitted because they are inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:

2.1	Order of the Bankruptcy Court, dated September 24 2019, confirming the Joint Prepackaged Plan of Reorganization of Halcón Resources Corporation, et al, under Chapter 11 of the Bankruptcy Code, together with such Joint Prepackaged Plan of Reorganization (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed September 26, 2019).
3.1	Amended and Restated Certificate of Incorporation of Battalion Oil Corporation (*formerly* Halcón Resources Corporation) dated October 8, 2019, as amended by the Certificate of Amendment, dated January 21, 2020 (Incorporated by reference to Exhibit 3.1 of our Annual Report on Form 10-K filed March 25, 2020).
3.2	Seventh Amended and Restated Bylaws of Battalion Oil Corporation (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed January 27, 2020).
4.1	Description of Battalion Oil Corporation's securities registered under Section 12 of the Exchange Act. (Incorporated by reference to Exhibit 4.1 of our Annual Report on Form 10-K filed March 25, 2020).
10.1	Senior Secured Revolving Credit Agreement, dated as of October 8, 2019, by and among Battalion Oil Corporation (*formerly* Halcón Resources Corporation), as borrower, Bank of Montreal, as administrative agent, and certain other financial institutions party thereto, as lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed October 8, 2019).
10.1.1	First Amendment to the Senior Secured Revolving Credit Agreement, dated as of November 21, 2019, by and among Battalion Oil Corporation (*formerly* Halcón Resources Corporation), as borrower, Bank of Montreal, as administrative agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed November 27, 2019).
10.1.2	Second Amendment to the Senior Secured Revolving Credit Agreement and Limited Consent, dated as of April 30, 2020, by and among Battalion Oil Corporation, as borrower, Bank of Montreal, as administrative agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed May 6, 2020).
10.1.3	Third Amendment to the Senior Secured Revolving Credit Agreement and Limited Waiver, dated as of October 29, 2020, by and among Battalion Oil Corporation, as borrower, Bank of Montreal, as administrative agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed November 2, 2020).

10.1.4	Fourth Amendment to the Senior Secured Revolving Credit Agreement dated as of May 10, 2021, by and among Battalion Oil Corporation, as borrower, Bank of Montreal, as administrative agent, and the lenders party thereto (Incorporated by reference to Exhibit 10.1.4 of our Quarterly Report on Form 10-Q filed May 17, 2021).
10.1.5	Fifth Amendment to the Senior Secured Revolving Credit Agreement dated as of September 24, 2021, by and among Battalion Oil Corporation, as borrower, Bank of Montreal, as administrative agent, and the lenders party thereto (Incorporated by reference to Exhibit 10.1.5 of our Current Report on Form 8-K filed September 30, 2021).
10.1.6	Amended and Restated Senior Secured Credit Agreement dated as of November 24, 2021, by and among Battalion Oil Corporation, as holdings, Halcón Holdings LLC, as borrower, the subsidiary guarantors party thereto, Macquarie Bank Limited, as administrative agent, and the lenders party thereto (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed November 29, 2021).
10.2	Warrant Agreement, dated as of October 8, 2019, by and between Halcón Resources Corporation and Broadridge Corporate Issuer Solutions, Inc., as warrant agent (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed October 8, 2019).
10.3	Registration Rights Agreement, dated as of October 8, 2019, by and among Halcón Resources Corporation and each of the parties thereto, as investors (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed October 8, 2019).
10.4†	Battalion Oil Corporation 2020 Long-Term Incentive Plan, effective as of January 1, 2020 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed January 31, 2020).
10.5†	Employment Agreement between Richard H. Little and Battalion Oil Corporation effective as of January 28, 2020 (Incorporated by reference to Exhibit 10.5 of our Annual Report on Form 10-K filed March 25, 2020).
10.6†	Employment Agreement between Daniel P. Rohling and Battalion Oil Corporation effective as of January 28, 2020 (Incorporated by reference to Exhibit 10.7 of our Annual Report on Form 10-K filed March 25, 2020).
10.7†	Employment Agreement between R. Kevin Andrews and Battalion Oil Corporation effective as of August 17, 2020 (Incorporated by reference to Exhibit 10.12 of our Quarterly Report on Form 10-Q filed November 9, 2020).
10.7.1†	First Amendment to Employment Agreement between R. Kevin Andrews and Battalion Oil Corporation effective as of August 7, 2021. (Incorporated by reference to Exhibit 10.8.1 of our Quarterly Report on Form 10-Q filed August 9, 2021).
10.22†	Form of Nonqualified Stock Option Award Agreement (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed January 31, 2020).
10.23†	Form of Base Restricted Stock Unit Award Agreement (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed January 31, 2020).
10.24†	Form of Performance-Based Restricted Stock Unit Award Agreement (Incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed January 31, 2020).
10.25†	Form of M&A Restricted Stock Unit Award Agreement (Incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K filed January 31, 2020).
21.1*	List of Subsidiaries of Battalion Oil Corporation
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Sarbanes-Oxley Section 302 certification of Principal Executive Officer
31.2*	Sarbanes-Oxley Section 302 certification of Principal Financial Officer
32*	Sarbanes-Oxley Section 906 certification of Principal Executive Officer and Principal Financial Officer
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document

101.DEF*	Inline XBRL Taxonomy Extension Definition Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104*	Cover Page Interactive Data File (embedded within the Inline XBRL document)

* *Attached hereto.*
† *Indicates management contract or compensatory plan or arrangement.*

The registrant has not filed with this report copies of the instruments defining rights of all holders of long-term debt of the registrant and its consolidated subsidiaries based upon the exception set forth in Item 601(b)(4)(iii)(A) of Regulation S-K. Copies of such instruments will be furnished to the SEC upon request.

ITEM 16. FORM 10-K SUMMARY

None.

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.

BATTALION OIL CORPORATION

Date: March 7, 2022

By: /s/ RICHARD H. LITTLE

Richard H. Little
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ RICHARD H. LITTLE Richard H. Little	Director and Chief Executive Officer	March 7, 2022
/s/ R. KEVIN ANDREWS R. Kevin Andrews	Executive Vice President, Chief Financial Officer and Treasurer	March 7, 2022
/s/ JONATHAN BARRETT Jonathan Barrett	Chairman of the Board	March 7, 2022
/s/ DAVID CHANG David Chang	Director	March 7, 2022
/s/ GREGORY HINDS Gregory Hinds	Director	March 7, 2022
/s/ ALLEN LI Allen Li	Director	March 7, 2022
/s/ WILLIAM ROGERS William Rogers	Director	March 7, 2022

Exhibit 21.1

Subsidiaries of the Registrant

Subsidiary	**State of Incorporation or Organization**
Battalion Oil Management, Inc.	Delaware
Halcón Holdings, LLC	Delaware
Halcón Energy Properties, Inc.	Delaware
Halcón Operating Co., Inc.	Texas
Halcón Field Services, LLC	Delaware
Halcón Permian, LLC	Delaware
Brazos Amine Treater Holdings, LLC	Texas
Brazos Amine Treater, LLC	Texas

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-236155 and 333-257181 on Form S-8, and Registration Statement No. 333-259415 on Form S-3 of our report dated March 7, 2022 relating to the financial statements of Battalion Oil Corporation (the "Company") in this Annual Report on Form 10-K of Battalion Oil Corporation for the year ended December 31, 2021.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 7, 2022

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers, we hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our reserves report dated February 2, 2022, included in the Annual Report on Form 10-K of Battalion Oil Corporation (the "Company") for the fiscal year ended December 31, 2021, as well as in the notes to the financial statements included therein. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our reserves reports into the Registration Statements on Form S-8 (File Nos. 333-236155 and 333-257181), and on Form S-3 (File No. 333-259415), as filed with the U.S. Securities and Exchange Commission.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons

Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
March 7, 2022

Exhibit 31.1

CERTIFICATION

I, Richard H. Little, certify that:

1. I have reviewed this Annual Report on Form 10-K of Battalion Oil Corporation;

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; and

   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 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: March 7, 2022

By: /s/ RICHARD H. LITTLE
Richard H. Little
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, R. Kevin Andrews, certify that:

1. I have reviewed this Annual Report on Form 10-K of Battalion Oil Corporation;

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; and

    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 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: March 7, 2022

By: /s/ R. KEVIN ANDREWS
R. Kevin Andrews
Executive Vice President,
Chief Financial Officer and Treasurer

Exhibit 32

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002
(Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), Richard H. Little, Chief Executive Officer, and R. Kevin Andrews, Executive Vice President, Chief Financial Officer and Treasurer, of Battalion Oil Corporation, (the "Company"), each hereby certifies that, to the best of his knowledge:

(1) The Company's Annual Report on Form 10-K for the year ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 7, 2022	/s/ RICHARD H. LITTLE Richard H. Little *Chief Executive Officer*
March 7, 2022	/s/ R. KEVIN ANDREWS R. Kevin Andrews *Executive Vice President, Chief Financial Officer and Treasurer*

This certification accompanies this Form 10-K and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, or otherwise subject to the liability of that Section.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

February 2, 2022

Mr. Daniel P. Rohling
Battalion Oil Corporation
3505 West Sam Houston Parkway North, Suite 300
Houston, Texas 77043

Dear Mr. Rohling:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2021, to the Battalion Oil Corporation (Battalion) interest in certain oil and gas properties located in North Dakota, Oklahoma, and Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Battalion. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Battalion's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Battalion interest in these properties, as of December 31, 2021, to be:

	Net Reserves			Future Net Revenue(1) (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	21,693.8	8,880.5	71,009.2	978,698.2	557,815.8
Proved Developed Shut-In	0.0	0.0	0.0	-2,571.3	-1,931.9
Proved Undeveloped	37,038.0	7,439.3	53,956.2	1,224,141.4	519,890.4
Total Proved	58,731.8	16,319.8	124,965.4	2,200,268.8	1,075,774.3

Totals may not add because of rounding.

(1) Future net revenue is after deducting estimated abandonment costs.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. No study was made to determine whether probable or possible reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Battalion's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Battalion's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2021. For oil and NGL volumes, the average West Texas Intermediate spot price of $66.55 per barrel is adjusted for quality, transportation fees, and market differentials. The oil differentials for the Monument Draw Area have been adjusted for existing contractual agreements. For gas volumes, the average Henry Hub spot price of $3.598 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $65.35 per barrel of oil, $27.59 per barrel of NGL, and $3.202 per MCF of gas.

Operating costs used in this report are based on operating expense records of Battalion. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Battalion are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Battalion and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells, production equipment, and facilities. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Battalion's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Battalion interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Battalion receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Battalion, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Battalion, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Neil H. Little, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Neil H. Little
By:
Neil H. Little, P.E. 117966
Vice President

/s/ Edward C. Roy III
By:
Edward C. Roy III, P.G. 2364
Vice President

Date Signed: February 2, 2022

Date Signed: February 2, 2022

NHL:SMD

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

> *Supplemental definitions from the 2018 Petroleum Resources Management System:*
>
> *Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.*
>
> *Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.